4.2 PUBLIC SAFETY: HAZARDS AND RISK ANALYSIS

Overview

The purpose of this section is to address public safety issues associated with the storage and handling of liquefied natural gas (LNG) at the floating storage and regasification unit (FSRU), which would be located 12.2 nautical miles (NM) (14 statute miles or 22.4 kilometers [km]) offshore, pipeline transport of unodorized and odorized natural gas, and onshore storage and injection of a natural gas odorant. This includes an evaluation of the worst-case consequences associated with the proposed LNG Deepwater Port (DWP).

Early on, the lead agencies determined that an Independent Risk Assessment would be required to address public questions about the safety of the proposed Project and commissioned a team of experts to prepare a site-specific evaluation of the design concept and security plans for the DWP taking into consideration local environmental conditions and the concerns expressed by the public during scoping.

The evaluation of potential public safety impacts associated with natural gas transportation by pipeline is relatively straightforward and draws on decades of operational history for hundreds of thousands of miles of transmission pipelines. Potential public safety impacts from the odorization facility are similar in nature to transportation and storage of almost any non-toxic but highly flammable liquid. Although the LNG industry has been operating for 40 years, fewer than 20 marine accidents involving LNG have occurred worldwide, none of which resulted in a significant release of LNG (the proposed FSRU would be a marine facility).

Evaluating the potential public safety impacts from the proposed Project required the use of a structured process that would:

- Identify and evaluate potential hazards;
- Define scenarios to bracket the range of potential accidents (resulting either from operations or terrorist attacks);
- Use state of the art computer models to define the consequences for each scenario (including the worst-case scenario);
- Compare the results to existing safety thresholds and other criteria; and
- Make the results available to decision makers and the public, while also ensuring that release of relevant information does not in turn create a security threat.

If the license and lease were approved, additional safety evaluations would be conducted throughout the design, construction and operation of the proposed Project.

The results of the Independent Risk Assessment are summarized in this section. However, since the Independent Risk Assessment Report contains sensitive security information (SSI), it cannot be made available to the general public, but it has been, and will be, made available for review by Federal, State, and local agency staffs and elected officials with safety and security responsibilities and clearances.

Following this introduction and the following discussion of the comments raised during the public scoping process, the hazards associated with the properties of LNG, natural gas, and natural gas odorant are presented in Subsection 4.2.1. The risk assessment process and the approaches used for further evaluating each of these three materials are described in Subsection 4.2.2, with the risk evaluations presented in Subsections 4.2.3 through 4.2.5.

Subsection 4.2.6 describes the regulatory framework that is currently in place and the roles and authorities of Federal and State agencies that are responsible for ensuring that the design, construction, and operation of this Project, if approved, place the highest priority on reliability and safety. Significance criteria for public safety impacts are defined in Subsection 4.2.7, with impacts and mitigation measures described in Subsection 4.2.8. The potential public safety impacts associated with alternatives compared to the proposed Project are described in Subsection 4.2.9, and references applicable to this public safety section are included in Subsection 4.2.10.

Public Scoping

As part of its Federal and State applications, BHP Billiton LNG International, Inc. (BHPB or the Applicant) submitted environmental analyses (EAs) for the proposed Project to the lead agencies for review. These EAs included discussions regarding safety issues. The Applicant also provided an assessment of the potential risks associated with LNG handling and preliminary engineering analyses used to support the conceptual design for the Project, which was also described in some detail in the application documents. This information was used to provide an initial definition and characterization of the proposed Project for presentation to the public at scoping meetings and to begin the essential collection of public input to this review process. This information also provided a starting point for technical staff from the lead and cooperating Federal and State agencies to begin to identify the types of independent analyses that would be needed to adequately evaluate the proposed Project and alternatives. Public scoping and technical staff system familiarization are shown in Figure 4.2-1 as the first steps in the risk assessment process.

Many of the issues raised by members of the public and representatives from public agencies during scoping meetings were related to the hazards and risks to public safety that might be posed by the proposed Project, both offshore and onshore. Comments received from the public during the public scoping meetings held from February 27 to March 31, 2004, regarding security- and safety-related issues were condensed into the general topic areas shown in Table 1.5-1, which cover the entire range of issues raised by the public during scoping. These topics have been expanded in Table 4.2-1 to show a more detailed description of the main public safety concerns and questions provided by the public. Table 4.2-1 also includes a brief summary describing how these concerns have been addressed in this Environmental Impact Statement/Environmental Impact Report (EIS/EIR).

Most of the safety-related issues raised during the public scoping meetings are addressed in this section; however, if more appropriate, some safety-related issues are presented in other sections. For example, the potential for seismic events, including tsunamis, is included in (Section 4.11, "Geologic Resources", and navigation safety is addressed in Section 4.3, "Marine Traffic." Cost recovery for emergency planning and response is discussed in the Subsection 4.2.8, "Impact Analysis and Mitigation." "In some cases, public comments asked for information that is not yet available or is outside of the parameters to be evaluated to determine impacts under the National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA). These comments are identified but not addressed in this EIS/EIR, but where such instances arise, the reasons for not providing the information in this EIS/EIR are noted. Specific discussions regarding Homeland Security—for example, sequences of events that might lead to accidents or measures prevent unauthorized access to the FSRU or an LNG carrier or to interdict an LNG carrier or other vessel that has been commandeered in a terrorist attack—are not included in the EIS/EIR or the supporting confidential technical report, the Independent Risk Assessment of the Proposed Cabrillo LNG Deepwater Port Project (AJ Wolford and Associates 2004). Such security-sensitive information has been compiled into a separate confidential report for review by Federal, State, and local agencies and elected officials with safety and security responsibilities and clearances.

4.2.1 Environmental Setting

The offshore environmental setting as it relates to hazards is discussed in Subsection 4.1.8, "Offshore Oceanography and Meteorology." The onshore environmental setting is described in other resource sections.

4.2.1.1 Properties and Hazards

The materials being stored and transported by the proposed Project include *LNG*, which would be transferred from tankers into the three spherical Moss storage tanks on the Applicant-owned FSRU, located approximately 12.2 NM (14 miles or 22.5 km) offshore where the ocean depth is about 2,900 feet (884 m). On the FSRU, the LNG would be allowed to expand or evaporate from its compressed liquefied form into *unodorized pipeline quality natural gas*. The natural gas would be fed through several pipes or risers into two subsea pipelines, which would transport the unodorized natural gas to the shore. Once onshore, an *odorant* would be added to the *natural gas* after it flows through a meter and into the onshore gas transmission pipeline system currently owned and operated by Southern California Gas Company (SoCalGas). The hazards associated with each of these materials are described below.

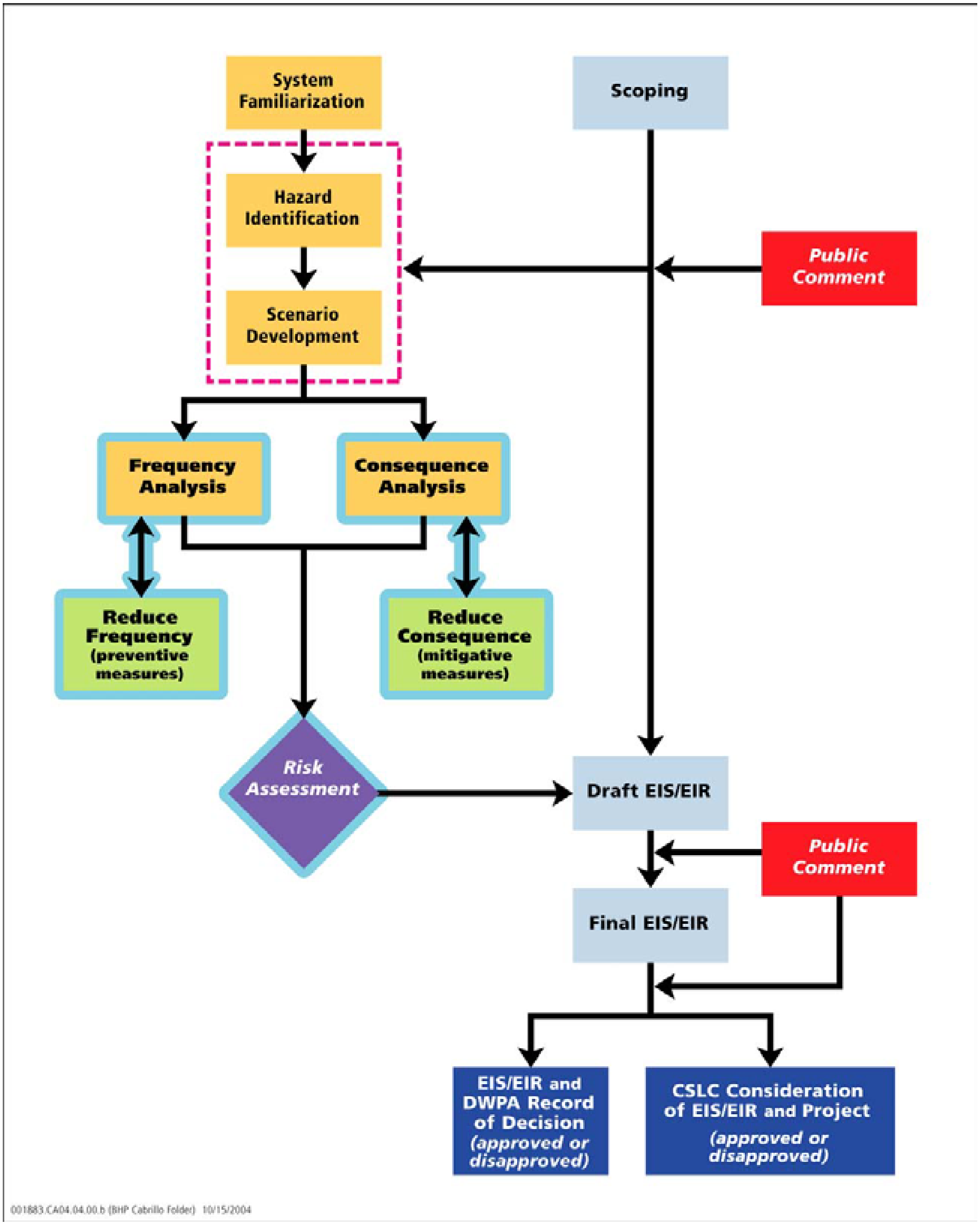


Figure 4.2-1 The Risk Assessment Process

Table 4.2-1 Public Scoping Comments – Security and Safety Topics

	Public Comment Topic	How Concern is Addressed in the EIS/EIR
1	The consequences of a worst-case terrorist attack from any initiating event, including a shoulder- or aircraft- fired missile or an aircraft hitting the FSRU.	Computer modeling included an improbable case where there was an instantaneous release of LNG from all three Moss storage spheres on the FSRU. No sequence of events was identified that could lead to this large a release, but this case was analyzed to answer public scoping questions about the absolute maximum distance where impacts might occur in a terrorist attack. In the model, the release was allowed to spread to its maximum downwind distance before being ignited. Modeling results indicated that serious injuries could occur at a distance of about 1.4 NM (1.6 statute miles, 2.6 km) away from the FSRU. This distance is greater than the 1,640-foot (500 meter [m]) safety zone radius but is less than the Applicant's proposed 2 NM (2.3 miles or 3.7 km) radius of a designated Area to be Avoided around the FSRU.
2	Vessel ramming or colliding with an LNG carrier or the FSRU or explosive placed on an LNG carrier or the FSRU; Identification and analysis of worst-case scenario(s); explosions and fires; and potential deaths from an LNG accident.	Two worst-case credible events that would cause a release of LNG and subsequent ignition of the natural gas cloud were identified as a result of computer analysis for a number of potential scenarios. Modeling indicated that members of the public could be seriously injured at a distance of about 1.1 NM (1.3 miles or 2.0 km) away from the FSRU as a result of Worst-Case Release #1. The annual frequency for occurrence of this event was estimated at about 6.1×10^{-7} per year (about 6 in ten million). For Worst-Case Release #2, serious injuries could occur at a distance of about 0.96 NM (1.1 miles or 1.8 km), at an annual frequency estimated at about 1.1 x 10-6 per year (about one in a million). Worst-case impacts for an incident involving an LNG tanker were not specifically modeled, although impacts from a credible release from a carrier transporting LNG in smaller Moss spheres would be no greater than for the FSRU Worst-Case Releases #1 and #2. These distances are greater than the 1,640-foot (500 m) safety zone radius but less than the Applicant's proposed 2 NM (2.3 miles or 3.7 km) radius of a designated Area to be Avoided around the FSRU.
3	Risk of hijacking of FSRU or LNG vessels and increased security concerns due to foreign vessels (and presumably foreign crews) plying the nearshore waters off the California coast.	United States Coast Guard (USCG) security requirements for LNG carriers arriving from foreign ports were increased after 9/11 and include providing a notice of arrival (NOA) that includes specific information about passengers and crew to the USCG National Vessel Movement Center (NVMC) at least 96 hours in advance of the vessel's arrival, with any changes to that at least 12 hours before entering port. No vessel would be allowed to dock at an offshore port until the identity of each person on board the LNG carrier has been screened and verified. Once moored, the crew would be subject to restrictions outlined in the Project's DWP Security Plan. Marine security and safety requirements are discussed in more detail in Appendix C to this EIS/EIR.
4	Enforcement of safety/precaution zones and notices to mariners.	See the discussion in Subsection 2.3.1.7. Marine security and safety requirements are also discussed in more detail in Appendix C to this EIS/EIR.
6	Locating the facility in less populated area.	The proposed mooring location for the FSRU is approximately 12.2 NM (14 miles or 22.4 km) offshore, which is an unpopulated area. The proposed and alternative shore crossings are in areas

Table 4.2-1 Public Scoping Comments – Security and Safety Topics

Public Comment Topic		How Concern is Addressed in the EIS/EIR
		where there is currently little or no residential housing. Proposed onshore pipeline routes have largely avoided areas with higher population densities.
7	Relocation of the natural gas odorant station.	Odorization options are included in the Impacts and Mitigation discussion in Subsection 4.2.8.
8	Contributing factors to event initiation, including seismic events that could cause liquefaction or tsunamis; weather events that could produce lightning, rough seas with strong swells from various directions, and onshore winds; material defects or equipment failures; dragging an anchor over the subsea pipeline; human error.	The potential for seismic events, including tsunamis, is included in Geologic Resources (Section 4.11). The potential for hazardous offshore weather and sea conditions is discussed in Subsection 4.1.8, Offshore Oceanography and Meteorology. An independent team of technical professionals evaluated initiating events and sequences of events to identify worst-case scenarios to be further analyzed. Scenarios that were deemed unlikely to cause impacts outside of the 1,640-foot (500 m) safety /exclusion zone — and hence would have no potential impacts to public safety—were not carried forward for further analysis. Engineering design requirements that address these issues are discussed in Subsection 4.2.6 and in 4.2.8, "Impact Analysis and Mitigation."
9	Potential for errant missiles from the neighboring Point Mugu and San Clemente Range Complex.	Consequences from an errant missile are bounded by—would not be worse than—the worst-case credible scenarios. The proposed routes for LNG carriers shown in this EIS/EIR were developed with significant input from the USCG and the Department of the Navy to reduce the potential for missile impacts.
10	Marine vessel accidents; Risks posed by additional ship traffic.	See the discussion in Section 4.3, "Marine Traffic."
11	Vapor-cloud dispersion under varying weather conditions, including marine inversions.	Computer modeling for worst-case releases included running cases with different wind profiles (atmospheric stability classes D and F) and wind speeds. Modeling of buoyant gases such as natural gas under varying meteorological conditions is the subject of an ongoing initiative by the United States Environmental Protection Agency (USEPA) and the private sector. However, assumptions made in the modeling for the proposed Project presume that the LNG does not begin to evaporate until the pool formed by a release has dispersed to a considerable distance. This assumption, coupled with the wind profile and speeds, is used to produce a conservative estimate (larger distance downwind potentially impacted by the release, which would be the expected result during a marine inversion) for horizontal dispersion of the LNG and the resulting natural gas cloud.
12	Adequacy of computer modeling for vapor dispersion—no data from large LNG spills or fires to verify the model results.	Computer modeling codes used to support the estimates of public safety impacts have been verified for smaller releases or events and are based on fluid mechanics and heat transfer engineering principles that are well understood. Assumptions used in the computer models were extremely conservative—i.e., selected to produce the most severe consequences—to help account for the lack of real-world accident data for such large releases and the uncertainties regarding the actual size of a release, time of ignition (if ignited at all), and weather conditions at the time of a major release.

Table 4.2-1 Public Scoping Comments – Security and Safety Topics

Public Comment Topic		How Concern is Addressed in the EIS/EIR
13	Emergency response (response time, funding, USCG role, local role).	Emergency planning for offshore incidents offshore at the FSRU or involving a supply boat or LNG carrier would be done in accordance with existing USCG regulations and would involve the Applicant, the USCG, and the Captain of the Port. Local funding or response capabilities would not be expected to be required to respond to these incidents. Local city and county emergency services and plans for responding to natural gas pipeline incidents onshore are in place, operational, and have a track record of responding appropriately to natural gas incidents. These capabilities, as well as cost recovery options for local planning and response agencies, are discussed in Subsection 4.2.8, "Impact Analysis and Mitigation."
14	Emergency evacuation (plans, routes).	No onshore evacuation plans or routes would be needed for an incident involving the FSRU or an LNG carrier. Emergency plans and response resources are already in place in local cities and counties (e.g., fire service, police, and emergency medical services) to protect the public in the event of an emergency involving existing onshore natural gas pipelines. Additional coordination and planning would be required, however, to ensure early notification of local authorities and response services (with onshore and offshore responsibilities) when any problem (potential leak or rupture) of pipelines carrying unodorized natural gas from the FSRU to the metering station onshore.
15	Hazard footprint of the onshore pipelines and cumulative effect of two pipelines.	Hazard footprints for onshore pipelines can be roughly estimated based on the "potential impact radius" for a high consequence area calculated in accordance with pipeline safety regulations (see the discussion regarding pipeline integrity management programs in Subsection 4.2.6.2). The potential for cumulative effects from two pipelines is discussed in Section 4.20, "Cumulative Impacts Analysis."
16	Cumulative impact of multiple terminals.	This is addressed in the cumulative impacts discussion contained in Section 4.20.
17	Training for workers.	Minimum requirements for worker training are specified in USCG and Department of Transportation (DOT) regulations and are discussed in this section.

LNG

As natural gas is cooled to a temperature of –259 degrees Fahrenheit (°F) (-162 degrees Celsius [°C]), it changes from a gas to a clear, colorless and odorless liquid in a process called liquefaction. Converting the gas to its cold liquid form reduces the volume by a factor of 600, which makes it possible to efficiently store and transport large quantities of this fuel in specially designed spherical tanks and tanker ships.

The specific gravity of LNG is 0.423, which means that it will float on water. LNG spilled onto the ocean surface will draw heat from the water and from the ambient air and will begin to rapidly evaporate or "boil," returning to its gaseous state. As it warms from its cold liquid state, LNG vapors are initially heavier than air, causing the vapor cloud to hug the surface and forming a vapor cloud resembling ground fog. As more heat is absorbed and the vapor continues to transition to its gaseous state, it becomes lighter than air, tends to rise, and can be more easily transported by wind. At this point, the expanded or evaporated LNG is now more appropriately called natural gas.

Hazards from LNG result from its very cold temperatures and from its dispersion characteristics. Brief contact with this cryogenic liquid can cause severe freezing burns to humans and wildlife. Direct exposure to the very cold liquid can also cause surface cracking or deeper fractures in plastics, fibers, and metals that make up the structural components and decking on board the FSRU. LNG is not toxic, but because the heavy vapor cloud tends to displace oxygen, LNG vapors pose an asphyxiation hazard.

LNG will not ignite; it must first evaporate to its gaseous phase, be mixed with air, and come into contact with an ignition source before it will burn. If the natural gas present in the vapor cloud is at concentrations within its flammable range (between about 5 and 15 percent by volume) and is ignited, the radiant heat will cause increased evaporation of the LNG pool surface, and the burning natural gas in the evaporating cloud above the pool will give the appearance that the pool is on fire. Radiant heat from such a fire would be significant and would pose a physical hazard to people, wildlife, and shipboard components. As with any hydrocarbon fuel fire, short-term effects on local air quality would also occur.

LNG will not explode in an unconfined space, but the rapid phase transition (RPT) from a liquid to a gas can occur so quickly that it can result in blast forces that may injure people or wildlife and damage shipboard components.

Natural Gas

Natural gas consists principally of methane, along with smaller amounts of heavier hydrocarbons, including ethane, propane, and butane. The acceptable ranges for hydrocarbon content, nonhydrocarbon gases, and contaminants for natural gas used in California are set through tariff agreements between the applicant and the public utility accepting the gas for distribution to its service area. In California, the ranges for some contaminants are set by the California Air Resources Board (CARB) and/or the local Air Pollution Control District (APCD)/Air Quality Management District (AQMD) to ensure that the emissions produced when this gas is burned meet air quality requirements.

Gas producers often treat natural gas to reduce the levels of nonhydrocarbon gases and contaminants and to control the energy content in order to meet the pipeline quality specifications imposed by the tariff. This helps limit the potential impacts on air quality when the natural gas is burned as a fuel and determines pricing based on the energy content or heat value in the gas. The Applicant has stated that the LNG to be imported to the Project will meet pipeline quality specifications without further treatment at the FSRU. The analyses conducted to evaluate the potential impacts to public safety are based on the presumption that the LNG and the resulting natural gas will be of pipeline quality with very high methane content (as high as 96 percent by volume).

Properties of Methane

The primary component of natural gas, methane, is colorless, odorless, and tasteless. It is not toxic but is classified as a simple asphyxiant, posing a slight inhalation hazard. Oxygen deficiency can occur if methane is inhaled in high concentration, resulting in serious injury or death. For this reason, pipeline safety regulations contained in Part 192.625 of Title 49 of the Code of Federal Regulations (CFR) require that an odorant be added to natural gas (see Subsection 4.2.1.3, "Natural Gas Odorant," which discusses odorizing natural gas).

Methane has an auto-ignition temperature (the minimum temperature required in the absence of a spark or flame to set methane on fire) of 1,166 °F (630 °C) and is flammable at concentrations between 5 and 15 percent by volume in air. Flammable concentrations of methane within an enclosed space in the presence of an ignition source can explode. However, because the specific gravity of methane in air is 0.55, which means that methane is buoyant at atmospheric pressures and temperatures and disperses rapidly in air, unconfined mixtures of methane in air are rarely explosive.

Natural Gas Hazards

The greatest hazard to the safety of the public and protection of property from natural gas transportation is generally a fire or explosion following a major rupture in a pipeline, although exposure to concentrations of natural gas in enclosed areas also poses an asphyxiation concern. Because the proposed Project involves transporting unodorized natural gas in the nearshore and shore-crossing pipelines before adding an odorant, the potential exists to release unodorized gas, which would not be detectable by people in the vicinity of the release.

Natural Gas Odorant

Federal safety regulations require that an odorant be added to natural gas to provide a warning property that is readily discernible by a person with a normal sense of smell at concentrations in air equal to 20 percent of the lower flammable limit (LFL) of the gas. This is also known as the lower explosive limit (LEL) and represents the minimum concentration that will support combustion in air. The LFL for methane, the primary component of natural gas, is a concentration of about 5 percent by volume in air, so natural gas must be odorized to be detectable at concentrations as low as 1 percent by volume in air.

Odorants generally include one or more mercaptan compounds, which are used to produce a distinctive, unpleasant smell familiar to anyone who has crossed paths with a skunk. (The mercaptan compounds produced in the animal's musk glands cause the offensive smell associated with a skunk's defensive spray. Mercaptans used for odorizing natural gas, however, are generally made from sulfur compounds found in crude oil.)

Mercaptan odorants are highly flammable and buoyant (lighter than air), colorless compounds that are generally insoluble in water, non-toxic at the concentrations found in natural gas, and have relatively low toxicity at the concentrations stored in bulk tanks or feed tanks at odorizing stations. The odorant gas that would be added to the natural gas shipped in the onshore pipeline is Spotleak 1039, a 50/50 mixture of tert-butylmercaptan (CAS 75-66-1) and tetrahydrothiophene (CAS 110-01-0) manufactured by Atofina Chemicals, Inc. (Atochem). Hazards associated with Spotleak 1039 are identified in the Material Safety Data Sheet (MSDS) for this mixture (Atofina 2004). These are summarized in Table 4.2.1-1.

Table 4.2.1-1 Hazards Associated with Natural Gas Odorant Spotleak 1039

Physical and Chemical Properties	Appearance/Odor Specific gravity Solubility in Water	Clear to pale yellow liquid with gas-like odor 0.904 at 60 °F (15.5 °C) (floats on water) Negligible
	Material is chemically stable under normal and anticipated storage and handling conditions. Avoid contact with strong oxidizers.	
Potential Health Hazards	Based on single exposure animal tests, is considered slightly toxic if swallowed, no more than slightly non-toxic if absorbed through the skin, and practically non-toxic if inhaled. Vapor may cause eye or respiratory tract irritation, May cause allergic skin reaction from repeated or prolonged contact. Material has a strong objectionable odor that may cause nausea, headache, or dizziness.	
First Aid Measures	If in eyes, immediately flush with water for at least 15 minutes. Get medical attention. If on skin, immediately flush with plenty of water. Remove contaminated clothing and shoes. Get medical attention. Wash clothing and thoroughly clean shoes before reuse. If swallowed, do not induce vomiting. Give water to drink. Get medical attention immediately. If inhaled, move to fresh air. If not breathing, give artificial respiration. If breathing difficult, give oxygen. Get medical attention.	
Fire and Explosion Hazards	Extremely flammable liquid and vapor. Vapor may cause flash fire. Use water spray, carbon dioxide, foam or dry chemical extinguishing media. Burning may produce hazardous products of incomplete combustion, including sulfur oxides, carbon monoxide and carbon dioxide, and hydrogen sulfide (H_2S).	
Accidental Release Measures	Ventilate the area. Contain spill by building a dike using absorbent material. Collect the liquid and solid absorbent into a drum approved for waste disposal. Flush area with water.	
Storage	Store in well ventilated area away from heat and sources of ignition such as flame, sparks and static electricity. Ensure that all storage and handling equipment is properly rated, grounded, and installed to satisfy electrical classification requirements. Static electricity may accumulate and create a fire hazard. All storage containers must be bonded and grounded during filling and emptying operations.	
Ecotoxicological and Fate Information	Slightly to moderately toxic to Daphnia magna, algae, and rainbow trout. Not readily biodegradable, and practically not bioaccumulable.	

4.2.2 The Risk Assessment Process

4.2.2.1 Risk Assessment Process for the LNG Deepwater Port

The number of LNG facilities is relatively small, and there have been too few incidents to provide any valid statistics regarding potential failures or release consequences for these types of facilities. Incident reports from similar facilities are helpful for discussions regarding accident scenarios and for generally characterizing potential hazards but do not provide enough information to develop an estimate of risk. A chronological list of accidents involving LNG transport and storage is included in Appendix C to this EIS/EIR. The potential risks to public safety from this proposed Project were developed using the following steps:

- An Independent Risk Assessment Team was formed, which included technical professionals with special expertise in marine operations and safety, security, risk communication, risk analysis, computer modeling, and LNG facility design and operation.
- The Independent Risk Assessment Team first identified the hazardous properties associated with the cryogenic liquids and gases that would be stored or transported.
- They then identified the scenarios that could lead to a release of LNG, based on public scoping comments, two intensive workshops (discussed below), an independent review of the Applicant's conceptual design and operations and safety plans and operational procedures, and an independent review of the Applicant's confidential security and safety plans and emergency procedures.
- Oceanographic and meteorology experts collected and summarized site-specific weather and ocean conditions for the proposed Project location offshore, to provide a basis for discussions about the potential impacts from various scenarios.
- In a parallel effort, marine operations and risk professionals collected and analyzed marine traffic numbers and patterns to identify the types and tonnage of marine vessels transiting waters near the proposed FSRU location.
- The next step was to screen out scenarios that were simply too unlikely to occur (no plausible initiating event, or no sequence of events that would result in a release) or that would not result in impacts outside of the immediate vicinity of the FSRU, i.e., scenarios that did not appear to have any potential for causing impacts to the public were not carried forward.
- Using site-specific meteorology and ocean conditions to help define some of the parameters, and local marine traffic data to define the types of vessels that might be most likely to collide with the FSRU, the next step was to conduct computer modeling for incident scenarios that were brought forward to identify the potential consequences or impacts from worst case and plausible scenarios.
- In another parallel effort, marine and risk specialists developed estimated frequencies for ship collisions.

- Finally, the team combined the consequence results with the frequency information to estimate the potential risks for each scenario.

Hazard Identification and Security Vulnerability Assessment

On behalf of the California State Lands Commission (CSLC), the USCG, and the United States Maritime Administration (MARAD), Ecology and Environment, Inc. (E & E) sponsored a Security Workshop on April 5, 2004 and a Hazard Identification and Analysis (HAZID) Workshop from April 6 through April 8, 2004 for the proposed Project. Both workshops were held in Long Beach, California.

The purpose of the workshops was to identify and analyze potential hazards related to the proposed Project. The workshops represent one component of the early agency-consultation process the Project team used to identify issues to be addressed in the EIS/EIR. The Project team, which included risk professionals from the lead agencies and EIS/EIR team, invited local, state, and federal agencies to nominate representatives with expertise in key disciplines such as engineering, hazard response, marine transportation, terrorism, fire protection, emergency response, security, safety and risk-related expertise to attend and participate in the workshops.

More than 55 technical specialists and engineers were invited to attend the workshops. In addition to the EIS/EIR team, 21 agency participants attended the Security Workshop, and 17 agency participants attended the HAZID. These participants included representatives from various local, state, and federal agencies, including the City of Oxnard, Port of Long Beach, the CSLC, the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), the California Department of Fish and Game (CDFG), the USCG, the United States Department of Energy (DOE), and the Federal Bureau of Investigation (FBI). Representatives of the Applicant and SoCalGas also attended specific sessions and answered questions about the design and operations of the proposed Project.

On Monday, April 5, 2004, on behalf of the lead agencies, E & E hosted the first workshop, a one-day Security Vulnerability Assessment (SVA). The Applicant provided a general overview of security measures planned for the proposed Project and was then excused from further participation in the SVA. The workshop participants explored a wide range of potential security threats along with current and potential preventive and mitigative risk-reduction measures. Following the SVA, the EIS/EIR team held a three-day HAZID workshop to identify safety and environmental hazards, focusing on those concerns that could potentially affect members of the public. The workshop leader trained participants in workshop methodology and common risk assessment terminology. The workshop leader also defined the following key terms to provide a common vocabulary, which enabled the participants and facilitators to communicate more effectively:

- *Hazard* – a condition (chemical or physical) that can potentially cause harm to people or damage to property or the environment;
- *Consequence* – a measure of the expected effects of an accident;

- *Threat* – a cause that can enable a hazard and produce a consequence;
- *Likelihood* – a measure of the expected occurrence of an event;
- *Risk* – a measure of economic loss or human injury in terms of both the incident likelihood and the magnitude of the loss or injury;
- *(Accident) Scenario* – the ordered sequence of events from cause to consequence;
- *Safeguard* – prevention or mitigation measure;
- *Prevention Measure* – a protective measure put in place to prevent threats from enabling a hazard; and
- *Mitigation Measure* – technical, operational and organizational measures that limit the chain of consequences escalating from the initial consequence.

A representative from the University of California at San Diego's Scripps Institute provided an introduction to offshore meteorology conditions in the vicinity of the proposed LNG DWP location. The Applicant described specific systems and operations of the proposed facility to familiarize the workshop participants and was then excused from further participation in the workshop sessions. The workshop leaders helped the group to systematically identify possible accident scenarios. The consensus listing of accident scenarios was recorded in a register, which formed the basis for the Independent Risk Assessment for the proposed LNG DWP. The workshop team evaluated the following systems associated with the proposed Project:

- Cargo Systems;
- Marine Systems;
- Support/Utility Systems;
- Onshore Pipeline;
- Turret/Swivel;
- Position Mooring System;
- Subsea Pipeline / Riser;
- Hull Structure;
- Installation / Hookup / Commissioning;
- Loading (from LNG Carrier);
- Gas Send Out;
- Shutdown Systems; and
- External Events.

The workshop participants also discussed the concerns identified through the public scoping process throughout both the SVA and HAZID workshops, including various terrorist scenarios (e.g., use of airplanes from local airports or shoulder-fired missiles to attack the facility, or LNG-vessel hijacking), the potential for catastrophic and smaller LNG releases due to equipment failure and human error, the integrity of the offshore and onshore pipelines, accidents involving other vessels, earthquakes, emergency response, validation of computer modeling, and other topics.

Scenario Development and Screening

Quantitative estimates of potential risks associated with the transportation of natural gas by offshore and onshore pipeline were determined to be readily available using historical pipeline incident data. Scenario development and screening was therefore focused on incidents involving LNG

Event scenarios were developed based upon information gathered during the public scoping meetings, the HAZID and SVA, and through an independent evaluation conducted for the lead NEPA and CEQA agencies by Kvaerner Process Services, Inc. an Aker Kvaerner company, of the Applicant's preliminary design and risk analysis (Kvaerner Process Services, Inc. [KPSI] 2004). KPSI reviewed the Applicant's conceptual engineering design, operations, and maintenance plans for topside processing and risk estimates for the vessel turret mooring/station keeping system and the turret gas export system, including the subsea control umbilical. In addition, security experts from E & E and the CSLC reviewed the Applicant's confidential security and emergency plans.

The scenarios were then screened based on the expert group's best professional judgment estimate of the likelihood of a potential sequence of events that might lead to an LNG release. A number of terrorist attack scenarios were screened out at this step. For example, a missile impact would not be expected to cause sufficient damage to produce a worst-case event. As part of the screening evaluation, approaches used in past terrorist attacks were evaluated to determine whether similar attempts would or would not have a potential for success.

Scenarios were also screened based on a best professional judgment estimate of the likelihood for impacting members of the public, i.e., for incidents with consequences that might extend beyond the 1,640-foot (500 m) safety zone around the FSRU. The reasoning used to eliminate some scenarios from further consideration is described in the Independent Risk Assessment. It is important to note that any number of initiating events might lead to similar consequences, which allowed the risk assessment team to identify a full range of potential scenarios to carry forward for further evaluation in the Independent Risk Assessment.

In addition to carrying forward major accidents where a credible sequence of events could be identified, a worst-case consequence for the FSRU and LNG carrier was also developed and carried forward. Although no sequence of events was identified that would lead to this large release, this scenario was carried forward to provide an assessment of the consequences of a worst-case terrorist attack. This worst case presumed the instantaneous release of all LNG from the three Moss storage spheres, which reflects a reasonable estimate of the total combined amount of LNG that might be present on the FSRU and a docked tanker, which would not be expected to exceed the total storage capacity of the FSRU. The consequences from this release provided insight into the potential physical effects of such a release without estimating the likelihood of occurrence.

Frequency Analysis

Frequency analysis involves estimating the likelihood of each of the event sequences that were identified in the hazard identification step. There are two basic forms by which likelihood can be expressed: *frequency* and *probability*. *Frequency* is the expected number of occurrences of the event per unit time. *Probability* is the measure of how likely it is that some event will occur.

Frequency data can be obtained from historical data, event-tree analysis, theoretical modeling, Bayesian analysis, judgment evaluation, and other techniques. Event-tree analysis was used due to the very high consequence, low likelihood events of interest for releases from the portions of the Project handling LNG.

Frequency of Terrorist Acts

Risk assessments of LNG facilities conducted before the September 11, 2001, terrorist attack focused on accidental-release scenarios. In these scenarios, the frequencies of events that lead to a particular outcome were assumed to be somewhat predictable based on the design, operational history, and historical incident data. Frequencies were not estimated for intentional acts of arson or sabotage, but the consequences were considered to be bounded by—would not be worse than—the worst-case credible scenarios.

The frequency or probability of arson, intentional sabotage, or a terrorist attack has not been estimated for the LNG DWP Independent Risk Assessment, because this cannot be reliably estimated. However, consequences of a terrorist attack on a tanker or the FSRU and its associated pipelines are expected to be bounded by the worst-case analyses (the release and ignition of the total volume of LNG stored on the FSRU), which were defined and evaluated without regard to the likelihood of any sequence of events that would lead to this event actually occurring. In addition, emergency planning undertaken by the responsible Federal, State, and local agencies to prevent or mitigate terrorist threats to marine shipping of hazardous materials applies to all marine shipping, not just LNG transport. Planning for specific intervention actions is subject to national security confidentiality and will not be addressed in this EIS/EIR.

Event-Tree Analysis

Event-tree analysis uses inductive logic and a graphical depiction to represent the various events that may follow from an initiating event. It uses branches to show the various possibilities that may arise at each step. It is often used to relate a failure event to various consequence models. Each branch is conditional on the previous answer in the tree. The frequency of each outcome is obtained by multiplying the outcome probabilities by the initiating event frequency. Event trees used to estimate accident frequencies for ship collisions with the FSRU are included in the Independent Risk Assessment.

Fault-Tree Analysis

Fault tree analysis is an analytical tool that uses deductive reasoning and a graphical depiction of that reasoning process to determine the various combinations that, if they occur, lead to the occurrence of an undesired (top) event. It is a structured, systematic approach that can be used to evaluate a single system or multiple systems and account for system interactions. It may be used in such a way as to link the top event of a fault tree with an event in an event tree.

LNG Incident and Consequence Analysis

In parallel with the frequency analysis, *consequence modeling* evaluates the resulting impact on the public and the environment if accidents or incidents occur. Based on the HAZID and SVA, it was determined that computer modeling should be conducted to evaluate the consequences that might result from worst-case scenarios. As a result of the workshop discussions, several release, fire, and explosion scenarios were selected for computer modeling. These scenario groups are summarized in Table 4.2.2-1; each group includes one or more possible event. Some of the scenario groups would be the result of operational accidents while others would be the result of mishaps or threats external to the facility operations.

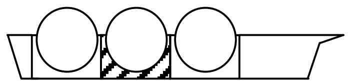
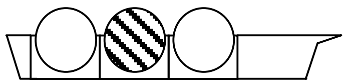
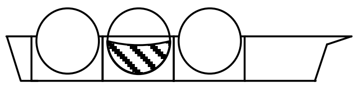
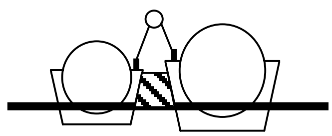
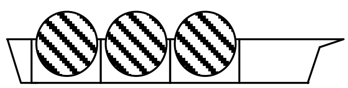
Computer modeling conducted in support of this EIS/EIR is summarized in Table 4.2.2-2, and included an analysis to better define the potential releases associated with ship collisions as well as three computational tools used to model the physical phenomena associated with release scenarios. A more detailed discussion of the computer modeling assumptions as well as descriptions of the models, their bases, and validation are included in the supporting Independent Risk Assessment report.

Scenario Groups 1, 2, and 4 depict operations accidents involving LNG spills that could result in the presence of a flammable mixture that subsequently ignited. Each of these three scenario groups included confined spaces and was investigated for explosion hazard.

Scenario Group 3 illustrates spills that could result from marine collisions from either runaway or drifting vessels that reach the FSRU site. The analysis showed that drifting vessels did not have sufficient kinetic energy to cause an LNG release. Cases carried forward in this group were based on high-energy collisions with the FSRU from a tanker and from a container ship. The size and tonnage of the tanker and container ships chosen for evaluation were based on an assessment of marine traffic in the vicinity of the proposed DWP.

Scenario Group 5 modeled spills that would place large quantities of LNG and cold natural gas onto the ocean surface and so would have the potential to result in very

Table 4.2.2-1 Summary of LNG Consequence Scenarios

Scenario Group	Sketch	Scenario Purpose and Cases Run*
Scenario 1: Explosion in Hull Void.		**Blast Forces.** Determine the potential impact to LNG spheres from an explosion located inside the FSRU hull.
Scenario 2: Explosion in a Storage Sphere.		**Blast Forces.** Determine the potential impact to LNG spheres from an explosion located in an FSRU cargo tank.
Scenario 3: Releases from a High Energy Marine Collision.		**Releases**. Model the releases from collisions with either runaway or drifting vessels that reach the FSRU site. Stability Class D, Wind 13.4 miles per hour (mph) (6 meters per second [m/s])
Scenario 4: Explosion Between FSRU and Docked Tanker.		**Blast Forces.** Determine the hull response and potential impact to spheres from an explosion occurring between the FSRU and a docked tanker.
Scenario 5:		
Scenario 5.1: Three-Tank Releases from a Terrorist Threat.		**Releases with subsequent ignition**. Stability Class D, Wind 13.4 mph (6 m/s)
Scenario 5.2: Single Tank Release Events.	See the figure for Scenario 2.	**Releases with subsequent ignition, for various meteorological conditions:** Stability Class D, Wind 13.4 mph (6 m/s) Stability Class D, Wind 13.4 mph (6 m/s) Stability Class F, Wind 4.5 mph (2 m/s) Stability Class D, Wind 22 mph (10 m/s)
Scenario 5.3: Releases without Ignition (rapid phase transition [RPT]).	See the figure for Scenario 2.	**Blast Forces**. RPT blast contours for overpressure and impulse pressure for cases simulating the instantaneous release of varying amounts of LNG, including a case based on the simultaneous LNG release from all 3 spheres.

Stability Class = Atmospheric stability class
* Detailed descriptions of the cases have been deleted due to SSI concerns.

Table 4.2.2-2 Summary of Computer Models Used for the LNG DWP Risk Assessment

Modeling Purpose	Type of Model	Program Source or Developer/Subcontractor	Scenarios
Damage from Ship Collision with the FSRU	Finite Element Modeling	Model developed and executed by Energo Engineering, Inc.	Scenario Group 3 (used to define the hole size or type of tank rupture)
LNG RPT or blast forces from explosion and fire	Computational Fluid Dynamics (CFD) program: Computational Explosion and Blast Assessment Model (CEBAM)	Proprietary program developed and executed by Analytical and Computational Engineering, Inc. (ACE).	Scenario Group 4 (used to define the blast forces) Scenario Group 5
Blast Force Impacts on the FSRU	WAMIT®, a radiation/diffraction panel program developed for the linear (first order) analysis of the interaction of surface waves with offshore structures.	Developed by Massachusetts Institute of Technology and Wamit, Inc.; model runs executed by Marine Innovation & Technology, Inc. (MinT).	Scenario Group 4 (used CEBAM-generated blast forces to estimate impacts on FSRU and tanker.)
LNG release, dispersion, and ignition.	Fire Dynamics Simulator (FDS)	Developed by the Building and Fire Research Laboratory at the National Institute of Standards and Technology (NIST), model runs executed by ACE.	Scenarios 3 and 5

large releases to the atmosphere. In this model (as well as in Scenario Group 3), the natural gas would be spread and pushed by the wind and would form a flammable cloud that represented a fire hazard. (Because confinement was not included in the model, there was no explosion hazard to investigate.) The flammable cloud would drift downwind, mix with air, and at the same time warm and become buoyant. Eventually, the concentration of natural gas would drop below flammable limits and no longer be a fire hazard. The fire hazard (thermal radiation) was evaluated for two worst-case flammable cloud conditions: 1) ignition when the cloud was at its maximum flammable mass, and 2) ignition when the flammable cloud had dispersed to a maximum distance, beyond which the gas concentration would be diluted by mixing with air to below the LFL for methane of 5 percent by volume, which is too lean to ignite. Scenario Group 5 investigated several catastrophic events involving single or multiple tank releases, regardless of the cause.

Computer Modeling Assumptions

Computer modeling of accidental releases must make some assumptions to guide the analysis. Since it is not possible to know in advance when an accident will occur, what the actual release might be, whether it will be day or night, or what the meteorological conditions might be at the time of the release, modeling is based on setting input parameters that are expected to provide conservative, worst-case, but at least somewhat realistic estimates for the spill size, plume concentrations of natural gas, blast forces, and areas that might be impacted by intense heat if the plume were ignited. The discussion below describes several of the key assumptions made for modeling LNG releases from a tank or tanks on-board the FSRU. A more detailed description of assumptions used to develop the computer models is provided in the Independent Risk Assessment.

- *High natural gas methane content.* The assumption that the natural gas would contain as much as 96 percent methane was based on initial information regarding the high methane content of the proposed natural gas source in western Australia and is reflected in the modeling of the natural gas as 100 percent methane.
- *Wind Profile is based on atmospheric stability Class D*. This results in a lower total cloud height but greater downwind dispersion than for very stable (Class F) conditions. This produces a larger estimate for the potential area that might be affected by the cloud and limits the vertical rise of the plume, which helps mimic what may occur during marine inversion conditions.
- *Wind Speed at 33 feet (10 m) height above sea level is 13.4 mph (6 m/s).* This was determined to be a reasonable estimate of winds that might be expected based on local weather buoy data. Higher wind speeds result in greater mixing of the natural gas cloud with air, which results in a smaller total mass that is in the flammable range compared with lower wind speeds. A lower wind speed results in a smaller estimated distance downwind where impacts could occur.
- *LNG is released instantaneously.* This produces greater flow velocities for the liquid LNG, which causes the liquid pool to spread faster and farther over the ocean surface than would be expected in an actual release, which results in a larger estimate for the area that would actually be affected by the release.
- *LNG does not evaporate as the liquid pool spreads*. Cold LNG would be expected to immediately begin to vaporize as it draws heat from the ocean surface and ambient air. (This was assumed to be the case in calculating the potential blast forces from the rapid phase transition of a release.) Applied to the plume release modeling, this assumption results in overestimating the liquid pool spread, which results in a larger estimate for the area that would actually be affected by the release.
- *Each FSRU Moss storage tank contains 24 million gallons (91,000 cubic meters [m^3]) of LNG*. As noted in Chapter 2, the capacity of each of the three Moss storage tanks would be about 24 million gallons (91,000 m^3). This assumption overestimates the volume of LNG that might be spilled by about 10 percent, which contributes to the conservative (more severe) estimate of the potential impacts from any actual LNG release.

4.2.2.2 Risk Assessment Process for LNG Carriers

The potential consequences of an accident involving an LNG carrier that might lead to a release of LNG were approximated based on the computer modeling results for worst-case credible releases from the FSRU. As described in Chapter 2, the FSRU's offloading facilities would be designed to accommodate LNG carriers ranging in capacity from 26.4 million gallons (100,000 m^3) to 58.1 million gallons (220,000 m^3) of LNG. Illustrations submitted by the Applicant indicate that these carriers would hold the LNG in two or more Moss storage tanks that would be similar to—but smaller than—the storage tanks on the FSRU. The worst-case consequences for a release of LNG from an incident involving a carrier would be expected to be less than the worst-case credible release from the FSRU. The potential frequency of collisions between LNG carriers and other vessels was not explicitly evaluated; collision frequencies based on site-specific marine traffic data were evaluated only for potential vessel collisions with the FSRU.

4.2.2.3 Risk Assessment Process for Natural Gas Pipelines and Odorization Facility

The transportation of natural gas and natural gas odorant and the storage of the odorant involve some risk to the public in the event of an accident and subsequent release. By definition, "risk" reflects the nature of the hazard, the potential consequences or impacts, and the probability or likelihood of occurrence.

There is a substantial amount of historical data readily available regarding the hazards and risks associated with pipeline transportation of natural gas. For decades, pipeline operators have been required to provide specific information regarding pipeline incidents to the DOT Research and Special Programs Administration's Office of Pipeline Safety (RSPA OPS). These data provide a sound basis for a quantitative estimate of the potential risks—the nature of the hazard, the potential consequences, and the probability of occurrence or frequency—based on reports collected over several decades from operation of hundreds of thousands of pipeline miles.

The CPUC also addresses risk management as part of its regulatory jurisdiction over 100,000 miles (161,000 km) of utility-owned intrastate natural gas pipelines, which transported 85 percent of the total amount of natural gas delivered to California's gas consumers in 2003.

Significantly less information is readily available with regard to the potential risks associated specifically with the transport and storage of the odorant that would be injected into the pipeline at the onshore odorization facility. These components of the proposed Project, however, are not particularly unique—flammable liquids are routinely transported by truck and transferred to larger fixed storage tanks throughout the U.S. and in this part of California. The potential risks associated with this part of the Project are described qualitatively in general terms, rather than quantitatively by estimating a numerical risk level.

4.2.3 Risk Evaluation – LNG Operations

4.2.3.1 Risk Evaluation – Offshore LNG Deepwater Port

The Independent Risk Assessment that was conducted in support of preparing this EIS/EIR combined the results from the computer-modeled scenarios with thresholds where serious injuries or fatalities might occur to identify the areas around the FSRU where one might expect to see serious injuries or fatalities from a worst-case incident involving the FSRU (the consequences). Based on site-specific marine traffic information, the potential frequency of an incident involving the FSRU was estimated (the probability). This represented a significant effort to develop reasonable, but conservative, estimates for the types of consequences that might result and the area that might potentially be impacted by incidents involving the LNG DWP.

Significant Public Safety Impact Thresholds

Significant public safety impacts are defined in Subsection 4.2.7 and include events that have the potential to cause serious injury or a fatality to members of the public, as well as any event that would cause long-term damage to the environment. No long-term impacts to the environment from LNG release scenarios were identified. Temporary and short-term impacts to the environment would include localized air quality impacts during any release or fire, and injuries and fatalities to seabirds and marine life in the vicinity of the release. These potential impacts are discussed in the air quality and marine biology sections of this chapter.

Based on the types of hazards associated with LNG (see Subsection 4.2.1.1), the potential impacts to people would be from direct contact with the very cold cryogenic liquid LNG, exposure to an atmosphere containing high concentrations of natural gas (where there would be insufficient oxygen), exposure to concussive blast forces caused by the rapid expansion of the LNG from a liquid to a gaseous phase, or exposure to radiant heat from a burning natural gas cloud. Each of these potential exposures was evaluated to identify whether these hazards would cause serious injury or fatalities to members of the public.

Information is available in the literature regarding the levels of these types of exposures that might be of concern. These have been developed primarily as part of defining criteria for engineering design and safety analysis, and for developing regulatory limits for exposure of workers or the public to these types of hazards. The units used to define exposures to these hazards reflect how the potential hazard is measured—asphyxiant hazards are defined in terms of the concentration of the gas in air by volume because that value represents how much oxygen has been displaced by the gas (and is therefore not available for people to breathe). Blast impacts are described in terms of the force applied over an area, or pressure, which is often presented in units of pounds per square inch (psi). Pressure can be measured in many ways—bars, inches of mercury, inches of water—where the units reflect how the pressure is actually measured (hence the term bar-o-meter, or barometer, for the instrument filled with mercury, water, or some other fluid used to measure pressure). Radiant heat from a fire is described as an amount of energy passing through a unit area in a particular period of time, which is often referred to as the “flux.”

Injury and fatality thresholds for potential impacts to people are often given as ranges and also often depend on the duration of exposure. For example, the information in the table below indicates that exposure to a radiant heat level greater than about 12.5

kilowatts per square meter (kw/m^2) (3,964 British thermal units per hour per square foot [BTU/hr-ft^2]) for more than about 35 minutes can be expected to cause a human fatality. Exposure at a higher radiant heat level of 37.5 kw/m^2 (11,890 BTU/hr-ft^2) can be expected to cause a fatality after a shorter exposure duration—less than 10 minutes. Where ranges were given in the literature, the lowest value that would cause a serious injury or fatality was selected. Thresholds for determining significant public safety impacts from LNG incidents are summarized in Table 4.2.3-1.

Summary of Computer Modeling Results

Based on the injury and fatality thresholds discussed above, the results of computer modeling were evaluated to determine whether the potential impacts could cause serious injuries or fatalities to members of the public.

Direct exposure of members of the public to LNG as a cryogenic liquid is not expected to occur outside of the 1,640-foot (500 m) safety zone. Computer modeling assumptions that presume an instantaneous release and no evaporation of the LNG until the spilled pool has expanded to a significant distance result in improbably large estimated distances where one might expect to encounter LNG on the ocean surface. These estimates also omit evaporation that would occur as liquid LNG drops from some height above the ocean surface and does not account for the warming and evaporation that would occur when the heavy spilled liquid initially plunges below the ocean surface. The “liquid pool spread” estimates used to develop worst-case impact areas for plume ignition should not be presumed to reliably estimate the actual size of a liquid pool of spilled LNG.

The potential downwind distance where asphyxiation or injuries due to oxygen deficiency might occur (as a result of exposure to vapor concentrations in excess of about 50 percent by volume) would be quite small compared with the potential area impacted by radiant heat transfer, which is based on the area where the natural gas concentration is greater than 5 percent by volume. The area of concern for potential injuries or fatalities due to asphyxiation is included within the area defined by serious injuries or fatalities from an ignited natural gas cloud and was not analyzed further.

Table 4.2.3-1 Threshold Levels Expected to Cause Serious Injury or Fatality to Humans

Cause and Type of Effect	Serious Injury		Fatality	
	Exposure Level	Exposure Duration	Exposure Level	Exposure Duration
Thermal Radiation - Burns				
Radiant Heat Level from Burning Natural Gas Cloud	12.5 kw/m^2 [a] (3964 BTU/hr-ft^2) 12.6 kw/m^2 [b]	30 seconds 7.2 minutes	12.5 kw/m^2 [a] (3964 BTU/hr-ft^2) 12.6 kw/m^2 [b] ——— 37.5 kw/m^2 [c] (11,890 BTU/hr-ft^2) 37.9 kw/m^2 [b]	“extended” 36.4 minutes ——— “immediate” 8.4 minutes

Table 4.2.3-1 Threshold Levels Expected to Cause Serious Injury or Fatality to Humans

Blast Forces – Ear Drum Rupture, Shock-Induced Damage to Lungs				
LNG Rapid Phase Transition	0.17 bar (2.4 psi) [d] Eardrum rupture	---	1.0 bar (14.5 psi) [d] Fatality	--
Ignition of Flammable Gas & Vapor Cloud	Ignition blast forces were not evaluated. Thermal radiation effects were presumed to have higher potential for causing serious injury or fatalities at a greater distance than the short-term blast effects from cloud ignition.			
Oxygen Displacement – Asphyxiation				
Unignited Natural Gas Cloud	50% by volume [e]	"minutes"	75% by volume [e] 87% by volume [e,f]	"few minutes" "immediate"
Exposure to Cryogenic Liquid – Freezing Burns				
LNG Pool Spread	Exposure to liquid LNG was not evaluated. The very conservative (i.e., large distance) estimate of the extent of a pool of spilled LNG is less than the distance where radiative heat levels would be expected to cause serious injuries to people.			

[a] Butler and Cohen. 1998. Firefighter Safety Zones: A Theoretical Model Based on Radiative Heating, Int. J. Wildland Fire 8(2): 73-77, 1998 0 IAWF.
[b] Gas Research Institute. 2000. Topical Report: A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines, C-FER Report 99068, GRI-00/0189.
[c] Spouge, John. 1999. A Guide to Quantitative Risk Assessment for Offshore Installations, Centre for Marine and Petroleum Technology, ISBN I 870553 365.
[d] Davies, P.A. A Guide to the Evaluation of Condensed Phase Explosions, J. Haz. Materials, 33 (1993) 1 33.
[e] Sax's Dangerous Properties of Industrial Materials. 1984. 6th Edition.
[f] American Conference of Governmental Industrial Hygienists .2001. Documentation of the Threshold Limit Values for Chemical Substances, 7th Edition.

Calculated blast forces resulting from RPT from the instantaneous release of LNG from the FSRU drop very quickly as the distance from the release point increases. Even for the worst-case (but improbable) scenario, presuming an instantaneous release from all three LNG Moss storage tanks on the FSRU, the estimated blast force at the 1,640-foot (500 m) safety zone boundary would be expected to be less than threshold levels necessary to cause serious injury to people. This is shown in Table 4.2.3-2 and illustrated in Figure 4.2.3-1.

Table 4.2.3-2 Scenario 5.3 Blast Contours Distances for Various Size RPT Explosions*

Distance ft (meters)	**3-Sphere Release**		**Partial Release #3**		**Partial Release #2**		**Partial Release #1**	
	Pressure (psi)	**Impulse (psi-ms)**	**Pressure (psi)**	**Impulse (psi-ms)**	**Pressure (psi)**	**Impulse (psi-ms)**	**Pressure (psi)**	**Impulse (psi-ms)**
50 (15.2)	40	9040	34	6250	31	3676	22	813
100 (30.5)	29	5320	23	2011	19	1150	11	365
200 (61.0)	18	1843	12	845	10	532	5.3	194
500 (152)	7	732	4.3	365	3.3	238	1.6	85
1000 (305)	3	393	2	197	1.3	124	0.6	43
1640 (500)**	1.5	248	0.9	121	0.7	77	0.34	27

Table 4.2.3-2 Scenario 5.3 Blast Contours Distances for Various Size RPT Explosions*

Distance ft (meters)	3-Sphere Release		Partial Release #3		Partial Release #2		Partial Release #1	
	Pressure (psi)	Impulse (psi-ms)	Pressure (psi)	Impulse (psi-ms)	Pressure (psi)	Impulse (psi-ms)	Pressure (psi)	Impulse (psi-ms)
2500 (762)	0.9	164	0.5	80	0.4	52	0.2	17
5000 (1524)	0.4	85	0.22	40	0.17	26	0.09	8.5

* Partial release volumes are included in the confidential Independent Risk Assessment but have been removed here due to SSI concerns.

**Distance: to FSRU Safety Zone = 1640 feet (500 m), to Area to be Avoided Zone: 2 NM (2.3 miles or 3.7 km)

Impulse forces in psi-millisecond (psi-ms) are included for completeness and to provide preliminary information for discussions of potential impacts on marine and avian wildlife (see Section 4.7, "Biologic Resources – Marine"). Blast forces shown in this table are applicable only in air and do not represent the physical forces or acoustic levels that marine life may be exposed to below the ocean surface.

Finite element modeling for a tanker collision with the FSRU indicated that the structural damage to the oil tanker would not result in a release of the tanker cargo. Finite element modeling for tanker and container ship collisions with the FSRU were used to develop estimates of the LNG releases for those cases.

The worst-case LNG release scenarios that resulted in potential impacts to public safety were drawn from computer modeling results for accident Scenario Group 3 (high-energy marine collisions) and Scenario Group 5 (other LNG releases of various sizes using varying directional flow, atmospheric stability classes, and wind speeds). These cases presumed the initial spreading of a pool of unevaporated LNG, then evaporation to form a natural gas cloud, followed by ignition at two different conditions: at the point where the natural gas cloud contained the largest volume of a mixture of natural gas and air within the 5 to 15 percent concentration flammable range and at the point where the natural gas cloud had dispersed to the maximum distance where ignition was still possible. This second condition (the maximum dispersion distance) represents the case where, beyond that distance, the concentration of the gas in air would be too low to support combustion.

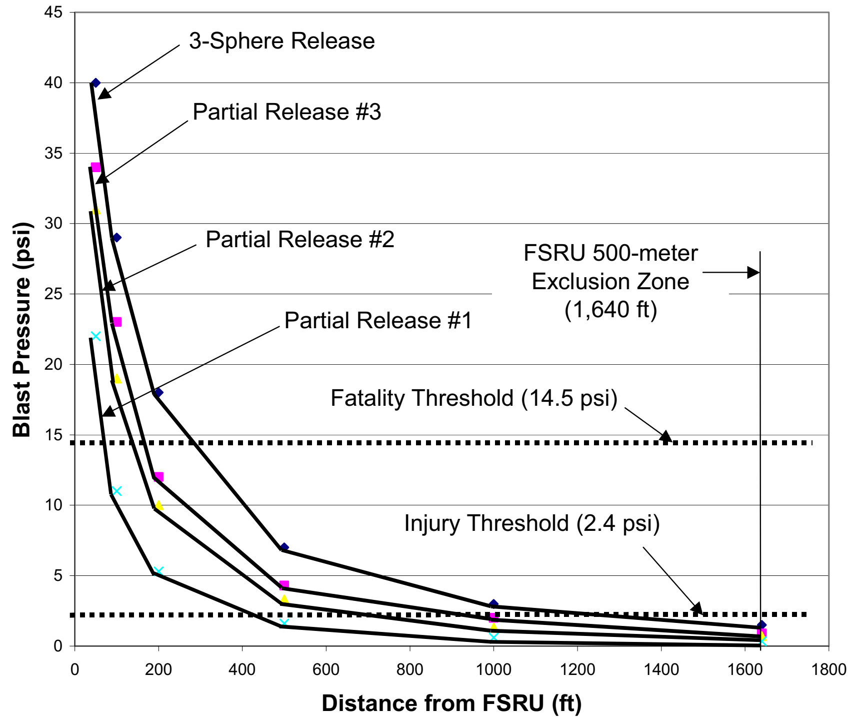


Figure 4.2.3-1 Blast Force Estimates for Various LNG Release Sizes

In answer to public scoping questions the "terrorist attack" scenario was evaluated, which presumed the instantaneous release of the LNG from all three storage tanks on the FSRU. The maximum distance where serious injuries would occur to members of the public from this "worst-case"—but not credible—scenario was estimated at 1.4 NM (1.6 miles or 2.6 km). This distance is greater than the 1,640-foot (500 m) safety zone radius but is less than the Applicant's proposed 2 NM (2.3 miles or 3.7 km) radius of a designated Area to be Avoided around the FSRU. Because no credible sequence of events could be developed that would lead to this kind of catastrophic release, however, this case was not carried through to determine an estimated frequency or risk.

Two worst-case credible scenarios were identified that presumed an incident leading to a release of LNG and subsequent ignition of the natural gas cloud at its maximum dispersion distance. Modeling indicated that members of the public could be seriously injured by radiant heat from the burning natural gas cloud at a distance of about 1.1 NM (1.3 miles or 2.0 km) away from the FSRU as a result of Worst-Case Release #1. The annual frequency for occurrence of this event was estimated at about 6.1×10^{-7} per year (about 6 in ten million). For Worst-Case Release #2, serious injuries from exposure to radiant heat from the burning natural gas cloud could occur at a distance of about 0.96 NM (1.1 miles or 1.8 km), at an annual frequency estimated at about 1.1×10^{-6} per year (about one in a million). These distances are greater than the 1,640-foot (500 m) safety zone radius but less than the Applicant's proposed 2 NM (2.3 miles or 3.7 km) radius of a designated Area to be Avoided around the FSRU.

The modeling assumptions limited the vertical height of the flammable natural gas cloud plume height to less than 330 feet (100 m) for each of the two worst-case credible scenarios. This was determined to provide an adequate representation of restrictions on the plume height if a release occurred during a marine inversion.

Figures 4.2.3-2 and 4.2.3-3 illustrate the "footprint" of the natural gas flammable cloud for the two worst-case credible releases when they have reached maximum dispersion distance. In these plan view figures, which represent a view of the flammable cloud as if looking down from a plane, the FSRU would be located at coordinates "0, 0." The cloud was presumed to be symmetrical (picture flipping the plume shown in the figure along the horizontal axis to get an idea of the shape of the entire cloud). The direction of the wind, which helps push the gas cloud farther from the FSRU, is along the horizontal axis. Larger color figures illustrating these dispersion footprints, the footprints for the radiant heat levels from the burning natural gas cloud, and plume elevations for the two worst-case credible releases are included in Appendix C to this EIS/EIR.

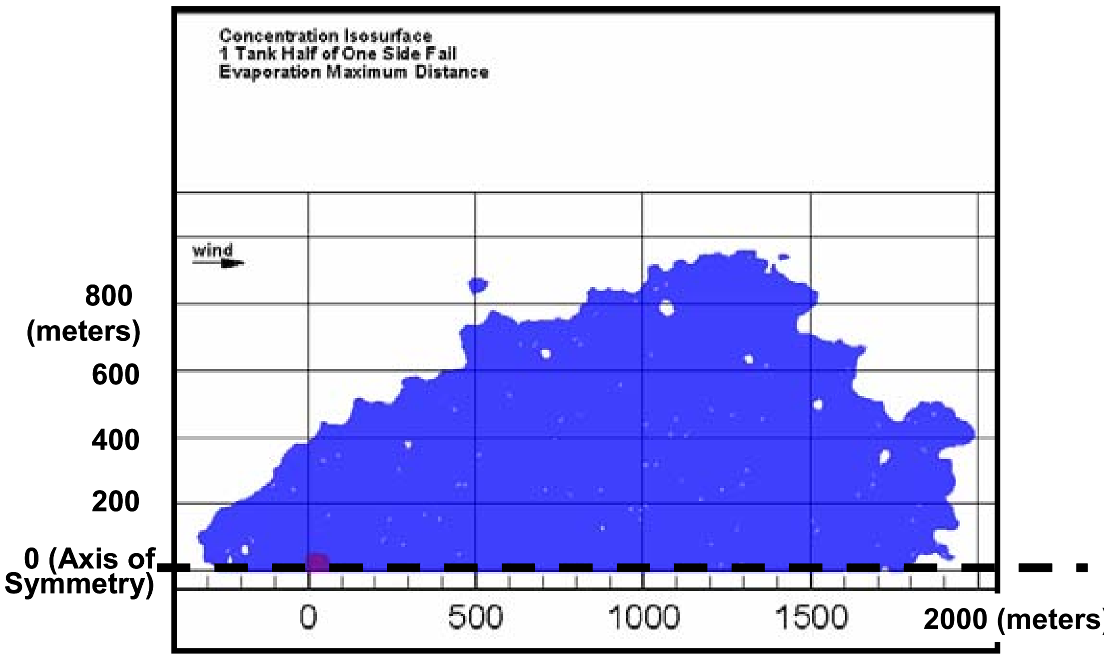


Figure 4.2.3-2 Worst-Case #1 Half-Plan View of Flammable Cloud at Maximum Dispersion Distance

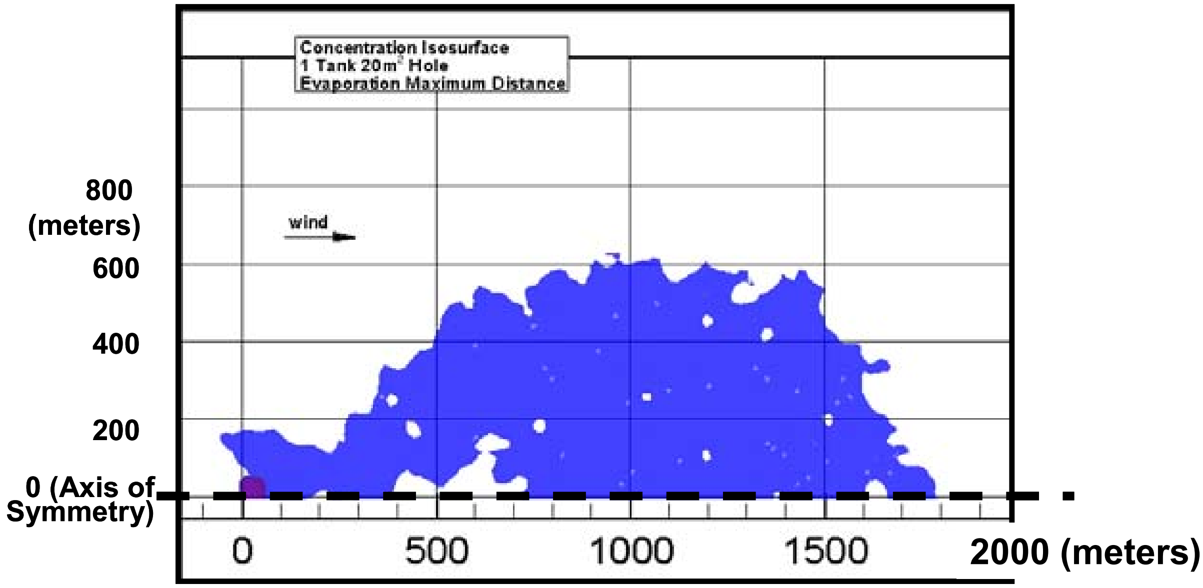


Figure 4.2.3-3 Worst-Case #2 Half-Plan View of Flammable Cloud at Maximum Dispersion Distance

Table 4.2.3-3, below, summarizes the modeling assumptions and numerical results for all of the “release and ignition” cases that were run.

4.2.3.2 Risk Evaluation – LNG Carriers

Worst-case impacts for an incident involving an LNG tanker were not specifically modeled, although impacts from a credible release from a carrier transporting LNG in smaller Moss spheres would not be expected to be greater than for the FSRU Worst-Case Releases #1 and #2.

The potential frequency of vessel collisions involving an LNG carrier was not estimated. The summary of major LNG accidents included in Appendix C to this EIS/EIR, however, identifies only five accidents since 1944 that occurred when LNG ships were at sea. The rest occurred when ships were in port and during loading and unloading operations. (Potential impacts from those types of incidents are encompassed in the worst-case scenarios for the FSRU.) None of these accidents resulted in injuries, fatalities, or a release of LNG, and only one was the result of a collision with another vessel. In 2002, the LNG ship Norman Lady collided with a U.S. Navy submarine, the U.S.S. Oklahoma City, east of the Strait of Gibraltar. (No LNG was released in this event.) This provides a general understanding that while collisions with LNG carriers are possible, they have been relatively rare and have not resulted in a release of LNG.

Table 4.2.3-3 Release Scenario Modeling Results – Scenario Group 3 and Scenario Group 5

		Worst-Case Credible Releases		Terrorist Attack		Other Cases Modeled				
Scenarios =		**#2**	**#1**	**TA-A**	**TA-B**	**A**	**B**	**C**	**D**	**Notes**
Release Case	Type of Release	Sudden	Sudden	Sudden	Sudden	Sudden	Sudden	Sudden	Sudden	
Release Case	Atmospheric Stability Class (Wind Profile)	D	D	D	D	D	D	F	D	
Release Case	Base Wind Speed meter/sec [mi/hr]	6 [13.4]	6 [13.4]	6 [13.4]	6 [13.4]	6 [13.4]	6 [13.4]	2 [4.5]	10 [22]	3
Release Case	Wall Surface Opened for Release (%)	20 sq meter	12.5%	100%	25%	100%	25%	100%	100%	
Release Case	Number of Tanks	1	1	3	3	1	1	1	1	
Release Case	LNG Volume in Spill (m^3) [cubic feet (ft^3)]	100,000 [3.53×10^6]	50,000 [1.75×10^6]	300,000 [1.06×10^7]	300,000 [1.06×10^7]	100,000 [3.53×10^6]	100,000 [3.53×10^6]	100,000 [3.53×10^6]	100,000 [3.53×10^6]	
Release Case	Obstructions in Simulation	None	None	None	Tanks	None	Tank	None	None	
Release Case	Background Species	Air	Air	Air	Air	Air	Air	Air	Air	
Release Case	Ambient temperature (^{o} C)[^{o}F]	21 [70]	21 [70]	21 [70]	21 [70]	21 [70]	21 [70]	21 [70]	21 [70]	
After Liquid Spread	Distance Down Range (m) [mile]	595 [0.37]	734 [0.46]	680 [0.42]	1200 [0.74]	700 [0.43]	685 [0.43]	700 [0.43]	700 [0.43]	
After Liquid Spread	Liquid Height (m)[ft]	8 [26]	13 [43]	7.5 [24.6]	8 [26.25]	7 [23]	6 [20]	7 [23]	7 [23]	
After Liquid Spread	Number of Symmetry Planes in Simulation	1	1	2	1	2	1	2	2	
After Evaporation – At Time of Max Flam	Avg. Flammable Height (m)[ft]	19 [62]	21 [69]	28 [92]	18 [59]	14 [46]	24 [79]	60 [197]	40 [131]	
After Evaporation – At Time of Max Flam	Maximum Flammable Mass (kg)[lb]	1.45×10^7 [3.20×10^7]	1.07×10^7 [2.36×10^7]	1.73×10^7 [3.88×10^7]	2.67×10^7 [5.89×10^7]	8.86×10^6 [1.95×10^7]	1.33×10^7 [2.93×10^7]	1.18×10^7 [2.60×10^7]	8.59×10^6 [1.89×10^7]	
After Evaporation – At Time of Max Flam	Time for Maximum Flammable Mass (s)	412	580	462	416	370	374	670	295	1
After Evaporation – At Max Dispersion	Avg. Flammable Height (m)[ft]	NR	NR	NR	NR	NR	NR	NR	NR	
After Evaporation – At Max Dispersion	Maximum Distance to LFL (m)[mile]	1790 [1.1]	1880 [1.17]	2590 [1.61]	1900 [1.18]	1865 [1.16]	1859 [1.15]	1000 [0.62]	1834 [1.14]	
After Evaporation – At Max Dispersion	Time for Maximum Distance (s)	562	720	295	466	570	600	920	420	1

Table 4.2.3-3 Release Scenario Modeling Results – Scenario Group 3 and Scenario Group 5

		Worst-Case Credible Releases		**Terrorist Attack**		**Other Cases Modeled**				
	Scenarios =	**#2**	**#1**	**TA-A**	**TA-B**	**A**	**B**	**C**	**D**	**Notes**
	Time for Complete Cloud Dissipation (gas concentration to <5% LFL)	NR	NR	NR	NR	NR	NR	NR	NR	
Fire Results (at Max. Flam. Mass)	Radiative Flux Distance ≥ 37.5 kw/m^2 (m)[mile]	1537 [0.96]	1881 [1.20]	2175 [1.35]	1736 [1.08]	1675 [1.04]	1721 [1.07]	Case not run	Case not run	2
	Annual Frequency	1.05 x 10^{-6}	6.08 x 10^{-7}	No Event Sequence	No Event Sequence	No Event Sequence	No Event Sequence	No Event Sequence	No Event Sequence	
	Radiative Flux Distance ≥ 12.5 kw/m^2 (m)[mile]	1554 [0.97]	1890 [1.21]	2190 [1.36]	1749 [1.09]	1695 [1.05]	1744 [1.08]	Case not run	Case not run	2
	Radiative Flux Distance ≥1.6 kw/m^2 (m)[mile]	1697 [1.04]	2010 [1.25]	2268 [1.41]	1813 [1.13]	1851 [1.15]	1941 [1.21]	Case not run	Case not run	2
Fire Results (at Max Dispersion Distance)	Radiative Flux Distance ≥37.5 kw/m2 (m)[mile]	1799 [1.12]	1881 [1.20]	2611 [1.62]	NR	NR	NR	NR	NR	
	Radiative Flux Distance ≥12.5 kw/m2 (m)[mile]	**1813 [1.13]**	**2008 [1.25]**	**2624 [1.63]**	NR	NR	NR	NR	NR	
	Radiative Flux Distance ≥1.6 kw/m^2 (m)[mile]	1901 [1.18]	2095 [1.30]	2704 [1.68]	NR	NR	NR	NR	NR	2

Notes			Radiative Heat Flux or Level:		
	1	Time includes Liquid Dispersion and Evaporation		1.6 kw/m2	No effect on people, no matter how long exposed
				12.5 kw/m2	Serious injury after 30 seconds, Fatality for extended exposure
	2	Distance from release location		37.5 kw/m2	Immediate human fatality for unprotected exposure
	3	Wind (Uo) at 10 meter elevation			

NR = Not Reported
NC = Not Calculated
NA = Not Applicable

4.2.4 Risk Evaluation – Offshore and Onshore Natural Gas Transportation

Pipeline accidents result in fewer fatalities annually than accidents involving other forms of transportation. A single pipeline accident, however, has the potential to cause a significant local impact, including injuries and fatalities to members of the public, property damage, disruption of community activities and traffic patterns, and disruptions to the local energy supply. The major hazards associated with the construction and operation of natural gas pipelines would include the potential release of natural gas, fires, and explosions. Fires occurring as a result of a release from a pipeline can also cause the release of potentially toxic products of incomplete combustion, can lead to secondary fires of nearby vehicles or structures, and can lead to wildfires. This subsection presents a summary of historic pipeline incident data as well as some of the regulatory requirements that have already been put in place—and will be implemented soon—to reduce the potential risks associated with pipeline accidents.

4.2.4.1 Offshore and Onshore - Historical Pipeline Incident Data

Pipeline Incident Reporting Requirements

For the purposes of this draft EIS/EIR, the risks associated with the pipeline transportation of natural gas have been estimated based on historical onshore and offshore pipeline-incident data compiled by RSPA OPS. The readily available data includes both onshore and offshore pipelines and does not distinguish between onshore and offshore pipelines incidents. Since February 9, 1970, all operators of transmission and gathering systems have been required to notify the DOT of any reportable incident and to submit a written report describing the incident.

The DOT changed reporting requirements after June 1984 to reduce the amount of data collected. Telephone notification of the National Response Center at 800-424-8802 is required at the earliest practicable moment, and Form F 7100.1 must be filed as soon as practicable but not more than 30 days after detection of an incident (49 CFR 191.9).

In 2004, reporting requirements for natural gas transmission pipelines were increased in scope and frequency as a part of implementation of pipeline integrity management programs required under 49 CFR 192, Subpart O. Operators of natural gas transmission pipelines must now submit additional information on a semi-annual basis for four performance measures for their pipeline integrity management programs. Utility-owned and operated natural gas transmission pipelines in California, including the proposed new pipelines that would be owned and operated by SoCalGas, are also subject to more stringent reporting requirements imposed by the CPUC, although these data are not reflected in the pipeline incident data discussed in this subsection. Pipeline reporting requirements are summarized in Table 4.2.4-1.

Table 4.2.4-1 Transmission Pipeline Incident and Safety-Related Condition Reporting Criteria

Reporting Period	Reporting Criteria
Pre-1984	**Report incidents that:** Caused a death or personal injury requiring hospitalization; Required taking any segment of a transmission line out of service; Resulted in gas ignition; Caused estimated damage to the property of the operator, or others, of a total of $5,000 or more; Required immediate repair on a transmission line; Occurred while testing with gas or another medium; or Was significant in the judgment of the operator, even though it did not meet the above criteria.
After June 1984 (Currently applicable)	**Report incidents that:** Resulted in a release of natural gas; and Caused a death or personal injury requiring in-patient hospitalization; Caused estimated property damage, including the cost of the gas lost, of more than $50,000; or Was significant in the judgment of the operator even though it did not meet the above criteria. **Report the following safety-related conditions that exist on a pipeline that is less than 220 yards (200 m) from any building intended for human occupancy or any outdoor place of assembly or that is within the right-of-way (ROW) of an active railroad, paved road, street, or highway:** • General corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure; • Localized corrosion pitting to a degree where leakage might result; • Unintended movement or abnormal loading by environmental causes such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline; • Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20 percent or more of its specified minimum yield strength; or • Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.
After August 2004 (Currently applicable)	**Semi-annually report** Pipeline Integrity Management Program status and actions: • The number of pipeline miles inspected versus program requirements; • The number of immediate repairs completed as a result of the integrity management inspection program; • The number of scheduled repairs completed as a result of the integrity management program; and • The number of leaks, failures, and incidents experienced, classified by cause.

Historical Pipeline Incident Causes and Mitigation Factors

Table 4.2.4-2 presents a summary of natural gas transmission pipeline incident data for three periods: 1970 to 1984 (under the old reporting requirements), the 1990s (under newer reporting requirements) and 2000 to 2003. No data are available yet under the most recent reporting changes for natural gas transmission pipelines. The data include onshore and offshore pipelines. Causes fall into three main categories: outside forces, corrosion, and defects in construction or materials. All other causes are combined into a fourth category that includes reports where the cause was not specified or was attributable to a less common cause.

The dramatic decrease in the total number of reportable incidents is illustrated in the last row of Table 4.2.4-2, which shows the total number of incidents and the annual average number of incidents each year for the period reported. Although part of the decrease was due to the 1984 change in reporting requirements, the decrease is also the result of implementing a number of pipeline safety initiatives over the past few decades, which have significantly reduced the number of incidents attributable to outside forces, which is likely due to better pipeline signage and more universal use of the One-Call systems before third-party excavations. As older pipelines were abandoned or upgraded to include cathodic protection systems, the numbers of incidents associated with corrosion events also decreased.

Table 4.2.4-2 Natural Gas Transmission Pipeline Incidents by Cause

Cause	1970 to 1984	1990-1999	2000-2003
Outside Forces - Total	**54%**	**41.1%**	**32.8%**
Car, Truck or Other Vehicle not related to Excavation Activity	36%		3.19%
Third Party Excavation Damage			8.12%
Operator Excavation Damage	3.9%		1.16%
Earth Movement	7.2%		1.16%
Weather: Lightning, Heavy Rains/Floods, High Winds	5.8%		2.32%
Other, Vandalism	0.81%		0.58%
Outside Forces			16.23%
Corrosion – Total	**17%**	**22.3%**	**27.0%**
Corrosion, External		8.62%	11.30%
Corrosion, Internal		13.5%	15.36%
Corrosion, Not Specified		0.13%	0.29%
Construction or Material Defect - Total	**21%**	**15.3%**	**17.7%**
Body of Pipe			2.03%
Component			1.45%
Construction or Material Defect			5.51%
Butt Weld			1.74%
Fillet Weld			0.58%

Table 4.2.4-2 Natural Gas Transmission Pipeline Incidents by Cause

Cause	1970 to 1984	1990-1999	2000-2003
Joint			1.74%
Pipe Seam Weld			2.90%
Ruptured or Leaking Seal/Pump Packing			0.29%
Threads Stripped, Broken Pipe Coupling			1.45%
Other – Total	**8%**	**21.4%**	**22.6%**
Fire/Explosion as Primary Cause			0.29%
Incorrect Operation			1.45%
Malfunction of Control/Relief Equipment			1.16%
Miscellaneous			3.77%
Other			12.75%
Rupture of Previously Damaged Pipe			0.29%
Unknown			2.90%
Total Incidents and Annual Average	**5,862 404/yr**	**771 77.1/yr**	**345 86.3/yr**

Factors Affecting Pipeline Incident Frequencies

The incident frequency that may be expected for a specific segment of pipeline varies widely in terms of age, pipe diameter, and level of corrosion control.

The dominant incident cause over the decades has been from outside forces, constituting 53.5 percent of all service incidents between 1970 and 1984 (Jones et al. 1986). This was also the case for incidents reported during the 1990s and during the 2000 to 2003 time frame. Outside forces incidents result from the encroachment of mechanical equipment such as bulldozers and backhoes, dragging boat anchors or trawling equipment; from earth movements due to soil settlement, washouts, or seismic hazards; from weather effects such as winds, storms, and thermal strains; and from willful damage.

Older pipelines also have a higher frequency of outside forces incidents, partly because their location may be less well known and less well marked than newer lines. In addition, the older pipelines contain a disproportionate number of smaller diameter pipelines, which have a greater rate of outside forces incidents. Small-diameter pipelines are more easily crushed or broken by mechanical equipment or earth movements.

The frequency of service incidents is strongly dependent on pipeline age. While pipelines installed since 1950 exhibit a fairly constant level of service incident frequency, pipelines installed before that time have a significantly higher rate, particularly due to corrosion. Older pipelines have a higher frequency of corrosion incidents, since corrosion is a time-dependent process. Further, more technologically advanced coatings and cathodic protection to reduce corrosion potential are generally used on newer pipelines.

Southern California Gas Company – Reportable Natural Gas Releases

Pipeline operators that experience reportable incidents involving natural gas pipelines must report these to the National Response Center (NRC). A database query (National Response Center 2004) for incident reports filed by SoCalGas identified a total of 29 incidents where natural gas had been released from a SoCalGas pipeline. A number of these incidents occurred as a result of third-party damage to distribution lines, but the remaining incidents involved transmission pipelines. These are summarized in Table 4.2.4-3.

Table 4.2.4-3 SoCalGas Reported Natural Gas Transmission Pipeline Incidents

Incident Report No./ Date	Location/ Cause/Description	Damages
May 5, 2004	Ventura County, Rose Avenue in El Rio. The impact of a vehicle collision pushed a passenger van off the roadway and onto a small natural gas line regulator station, snapping off the pressure valve.	Note: Approximately 700,000 ft^3 (19,822 m^3) of natural gas was released, roadways within an eight-square mile were blocked to traffic, and staff and students at nearby Rio Mesa High School were directed by emergency services to shelter in place (i.e., remain inside with doors and windows shut). The valve was reportedly replaced within an hour, and no serious injuries were reported. This incident involved a distribution line, not a transmission line, and did not meet minimum criteria to require reporting to the NRC. The incident did meet CPUC reporting criteria and was reported to CPUC by SoCalGas.
591361 January 16, 2002	Kern County, Valley Acres, in the right-of-way 0.25 mile (0.4 km) south of Hwy 119. 26” transmission line break due to unknown causes, est. release duration 2 hours.	$50,000 in damages, No injuries or fatalities noted. Evacuated 24 private citizens. Closed Hwy 119 north/south.
565500 May 9, 2001	Los Angeles County, Santa Clarita, 26623 May Way. Odor complaint due to purging a high-pressure gas transmission line. Estimated 2-hour release.	12 injuries noted in report. No hospitalizations, fatalities, or evacuation noted.
555595 February 2, 2001	Santa Barbara County, Cuyuma, 5 miles (8 km) from city, 0.5 mile (0.8 km) west of Hwy 133, and 2.5 mile (4.0 km) south of Hwy 166. Third party excavation ruptured underground transmission line.	$80,000 in damages, No injuries, fatalities, or evacuation noted at time of report.

Table 4.2.4-3 SoCalGas Reported Natural Gas Transmission Pipeline Incidents

Incident Report No./ Date	Location/ Cause/Description	Damages
468762 December 24, 1998	Kern County, 8 miles (12.9 km) south of Lost Hills. "Transfer" pipeline failed due to "earth movement." Release was secured.	None noted in report.
461704 October 28, 1998	Riverside, Hwy 91 at Arlington Avenue. 30-inch (0.76 m) transmission line, 2-inch (5 centimeters [cm]) fitting ruptured by a contractor. Release is adjacent to a railroad line.	Rail traffic through the area stopped.
426636 March 2, 1998	Ventura County, Somis, 4149 Clubhouse Drive. 24-inch (0.6 m) transmission line break due to a landslide.	> $50,000 in damages, No injuries, fatalities, or evacuation noted at time of report.
426474 March 1, 1998	Los Angeles County, Santa Clarita, Saticoy. 20-inch (0.5 m) transmission line break due to a landslide.	> $50,000 in damages, No injuries, fatalities, or evacuation noted at time of report.
366376 November 1, 1996	Los Angeles County, Sylmar Expansion joint ruptured on transmission line.	> $50,000 in damages, No injuries, fatalities, or evacuation noted at time of report.
287958 April 20, 1995	Ventura County, Line 1003 behind the community of LaConchita 16-inch (0.4 m) transmission line break due to landslide. Line isolated.	> $50,000 in damages, No injuries, fatalities, or evacuation noted at time of report.
217077 January 17, 1994	Los Angeles County Earthquake. No releases noted. Preliminary information on service status: 1200 service outages, 3 transmission lines, and 25 distribution lines out of service.	Unknown at the time of the report.

4.2.4.2 Estimated Pipeline Safety Risks

The service incidents summarized above in Table 4.2.4-2 include pipeline failures of all magnitudes with widely varying consequences and pipelines of all ages and diameters. About two-thirds of the incidents were classified as leaks; the remaining one-third were classified as ruptures, implying a more serious failure.

The SoCalGas-reported natural gas pipeline incidents shown in Table 4.2.4-3 provide a general idea of the nature, frequency, and consequences of accidents that have been experienced by this pipeline operator.

Table 4.2.4-4 presents the annual summaries of reported incidents associated with onshore and offshore natural gas transmission and gathering pipelines from 1986 to 2003. During this 18-year period, the data indicate that efforts to improve pipeline safety had some success: there is an overall decreasing trend in the numbers of fatalities and injuries due to incidents associated with these pipelines.

The data show that the annual average for the period 1986 through 2003 was 3.3 fatalities per year during the operation of about 324,000 miles (521,430 km) of onshore and offshore natural gas transmission and gathering pipelines. Although the readily available data is not categorized by onshore versus offshore pipelines, the Marine Board of the National Research Council has conducted an interdisciplinary review and assessment of the many technical, regulatory, and jurisdictional issues that affected the safety of all types of marine pipelines in the United States' offshore waters during the early 1990s. The Committee on the Safety of Marine Pipelines reviewed the causes of past pipeline failures, the potential for future failures, and the means of preventing or mitigating these failures. In 1994, the Marine Board issued a report, *Improving the Safety of Marine Pipelines.* The committee determined that the marine pipeline network does not present an extraordinary threat to human life. Pipeline accidents involving deaths or injuries were described as rare (68 Federal Register [FR] 69369, December 12, 2003).

The historical data shown in Table 4.2.4-4 include incidents for older pipelines that were not subject to the more stringent design and safety criteria applied to new pipeline construction and a wide variety of pipeline sizes and types. These standards are discussed briefly in the next subsection and would be expected to reduce—and in some cases significantly decrease—the potential frequency of incidents associated with the Project pipelines.

Table 4.2.4-4 Annual Incident Summaries – U.S. Gas Transmission Pipelines [a]

Year	Incidents	Fatalities [b]	Injuries [b]	Property Damage	Total Transmission and Gathering Pipelines (miles/km)
1986	83	6	20	$11,166,262	321,653 (517, 650)
1987	70	0	15	$4,720,466	323,988 (521,410)
1988	89	2	11	$9,316,078	320,202 (515,315)
1989	103	22	28	$20,458,939	320,070 (515,102)
1990	89	0	17	$11,302,316	324,410 (522,087)
1991	71	0	12	$11,931,238	326,575 (525,571)
1992	74	3	15	$24,578,165	324,097 (521,584)
1993	95	1	17	$23,035,268	325,319 (523,550)
1994	81	0	22	$45,170,293	322,849 (519,575)
1995	64	2	10	$9,957,750	327,866 (527,649)
1996	77	1	5	$13,078,474	321,791 (517,872)
1997	73	1	5	$12,078,117	328,765 (529,096)
1998	99	1	11	$44,487,310	331,862 (534,080)
1999	54	2	8	$17,695,937	328,765 (525,096)
2000	80	15	18	$17,868,261	328,493 (528,658)
2001	86	2	5	$23,610,883	312,070 (502,228)

Table 4.2.4-4 Annual Incident Summaries – U.S. Gas Transmission Pipelines [a]

Year	Incidents	Fatalities [b]	Injuries [b]	Property Damage	Total Transmission and Gathering Pipelines (miles/km)
2002	82	1	5	$25,464,568	326,542 (525,518)
2003	97	1	8	$39,513,153	317,582 (511,099)
Totals 1986- 2003	**1,487**	**60**	**232**	**$365,433,478**	**---**
Average Annually 1986- 2003	**81.5**	**3.33**	**12.89**	**$20,301,860**	**324,000 (521,428)**

[a] 1986 through 2003, U.S. DOT Office of Pipeline Safety, Gas Pipeline Statistics, accessed 06/11/2004 at http://ops.dot.gov/stats/tran_sum.htm and http://ops.dot.gov/stats/GTANNUAL2.HTM

[b] Injury and fatality data reported are for transmission and gathering lines, and include workers as well as members of the public.

Nevertheless, a very conservative estimate of the potential unmitigated risks associated with the proposed Project pipelines can be drawn from this information. Conservative estimates of the unmitigated annual frequencies and risks that would be associated with the Project pipelines are shown in Table 4.2.4-5. As shown in the table, there is a moderate chance that the Project pipelines would experience a reportable incident in any year. There is a very small chance that this incident would result in injuries, and an even smaller chance that a fatality would occur. Mitigating actions that would be taken to reduce the potential for causing a significant impact (see Subsection 4.2.7, “Significance Criteria”) are described in Subsection 4.2.8, “Impact Analysis and Mitigation.”

Table 4.2.4-5 Estimated Annual Incident Frequencies/Risks: Gas Transmission Pipelines [a]

Event or Outcome	Average Total Number per Year, U.S. Pipelines	Estimated Frequency (per pipeline mile)[b]
Reportable incident	81.5	2.5×10^{-4}
Injury requiring in-patient hospitalization	12.9	4×10^{-5}
Fatality	3.3	1×10^{-5}

[a] Estimated worst-case frequency. These are extremely conservative estimates based on a nationwide mix of old and new transmission and gathering lines. The unmitigated frequencies for newly installed transmission lines (such as those proposed for this Project) would be expected to be much lower.

[b] Based on operation of a total of 324,000 miles (521,316 km) of gas transmission pipelines throughout the U.S. each year.

Although there are no regulatory risk tolerance thresholds that would govern a decision to approve or deny the proposed Project, the public risk tolerance thresholds developed by nearby Santa Barbara County (2003) for onshore projects can be used as a general comparison. The very conservative estimate of the unmitigated potential annual risk of a fatality from operation of the proposed Project pipelines range is about 1×10^{-5} per mile (1.6 km) of pipeline. This level of risk would be considered acceptable under the Santa

Barbara threshold scheme, with no additional mitigation suggested to further reduce the potential risk. The potential annual risk of a fatality associated with the new pipelines to be constructed as part of the proposed Project, however, would be expected to be less (and potentially considerably less) than this due to the current requirements for increased safety margins in design, greater inspection detail and frequencies, and the implementation of the new pipeline integrity management program requirements for high consequence areas (HCAs) identified along these pipelines.

For comparison, the nationwide totals of accidental fatalities from various manmade and natural hazards as listed in Table 4.2.4-6 provide a relative measure of the industry-wide safety of natural gas pipelines. Direct comparisons between accident categories should be made cautiously because individual exposures to hazards are not uniform among categories. As shown in Table 4.2.4-6, the potential impact to the public from the operation of natural gas transmission pipelines in the United States (U.S.) is considerably less than for other types of transportation. In addition, the table illustrates the difference in the safety record for gas transmission pipelines compared to gas distribution pipelines, which tend to be smaller in diameter, have thinner wall thicknesses, may be constructed of plastic pipe rather than steel, and are often not as well marked as transmission system piping.

Table 4.2.4-6 Annual Transportation Accidental Deaths

Type of Accident	Average Number of Fatalities per Year [a]	Most Recent Year Fatalities (2002/2003)
All transportation accidents and adverse effects (1990, 1995, 1997, 1998 average) [a]	93,525 [a]	44,888 [c]
Motor vehicles (1990, 1994-1998 average) [a]	42,114 [a]	42,643 [c]
Motor vehicle traffic collisions in California (2002)	---	4,089 [d]
Railroad accidents (1990-1998 average) [a]	1,158 [a]	767 [c]
Aviation accidents	---	707 [c]
Marine accidents	---	759 [c]
Gas Distribution Pipelines (1986-2003 average) [b]	16.8 [b]	11 [b]
Gas Transmission Pipelines (1986–2003 average) [b]	3.3 [b]	1 [b]

[a] All data, unless otherwise noted, reflect statistics from the U.S. Department of Commerce, Bureau of the Census, Statistical Abstract of the United States, 118th Edition (1998)

[b] U.S. Department of Transportation, Office of Pipeline Safety. 2004 http://ops.dot.gov/stats.html

[c] National Gas Institute's Daily Gas Price Index. September 7, 2004. "NTSB Reports Gas Pipeline Fatalities Up Slightly in 2003." Note that the increase was due to distribution line incidents, not transmission line accidents.

[d] California Department of Finance, Number of Motor Vehicle Traffic Collisions and Persons Killed and Injured. 2002. http://www.dof.ca.gov/html/fs_data/stat-abs/tables/j8.xls

4.2.5 Risk Evaluation – Odorization Facility

Because odorants are highly flammable, incidents involving releases greater than 100 pounds (45.4 kilograms [kg]) of these materials must be reported to the National Response Center (see 40 CFR 302.5 and 302.5). A database query (National Response Center 2004) for reports involving "odorant" or either of the two chemicals that make up Spotleak 1039 identified a total of six reported incidents where these materials were released. These are summarized in Table 4.2.5-1. A number of other incidents were identified where materials with similar flammable properties or chemical composition were released. These are included in Table 4.2.5-1 to provide a general idea of the types and sizes of releases that might occur during transportation, storage, or piping transfer of the odorant. While it is not possible to extrapolate this information to an estimated risk level, these reports indicate that in general, such releases have tended to be infrequent, relatively small, and have resulted in no injuries or fatalities to members of the public.

Table 4.2.5-1 Reportable Odorant Incidents

Incident Report No./ Date Responsible Party	Location/ Cause/Description	Damages
Releases of Odorant or Spotleak 1039 chemicals (tertiary butyl mercaptan and tetrahydrothiophene)		
565883 May 12, 2001 Consolidated Freightways	El Paso, Texas, freightways terminal. A forklift punctured a 55-gallon (0.2 m^3) drum, releasing 2 gallons (7.6 liters [L]) of tetrahydrothiophene. Cleanup crews overpacked the drum to contain the release.	No fire, fatalities, or evacuation were noted at time of report. One person was injured and hospitalized due to chemical exposure.
390236 June 7, 1997 PECO Energy	West Conshohocken, Pennsylvania. The odor injection system malfunctioned; residents reported increased odor appearing in pipes. (Malfunction apparently caused injection of increased amounts of odorant into pipeline).	No fire, injuries, hospitalizations, or fatalities, or evacuation noted at time of report.
349975 July 1, 1996 ELF Atochem	ELF Atochem plant in Houston, Texas Disk failed on a storage tank, releasing 100 pounds (45 kg) of tertiary butylmercaptan.	No fire, injuries, hospitalizations, or fatalities, or evacuation noted at time of report.
320626 January 17, 1996 Chevron, USA	El Segundo, California. A flange leak on an odorant vessel released 1 gallon (3.8 L) of tetrahydrothiophene.	No fire, injuries, hospitalizations, or fatalities were noted at time of report. Four nearby businesses were evacuated for 2 hours due to the strong odor.

Table 4.2.5-1 Reportable Odorant Incidents

Incident Report No./ Date Responsible Party	Location/ Cause/Description	Damages
121642 June 12, 1992 Atochem North America	Houston, Texas plant. A gasket failed on a rail car carrying tertiary butylmercaptan, releasing 200 gallons (0.8 m^3). The spilled material was routed to the onsite wastewater treatment system, while the pressure in the rail car was bled off.	No fire, injuries, hospitalizations, or fatalities, or evacuation noted at time of report.
43705 October 15, 1990 Distrigas of Massachusetts	Everett, Massachusetts. During priming of the pumping system, 4 ounces (0.1 L) of odorant were released.	No fire, injuries, hospitalizations, or fatalities, or evacuation noted at time of report.
Releases of Similar Chemicals		
572926 July 14, 2001 ELF Atochem	Detroit, Michigan Rail tank car carrying methyl mercaptan exploded due to unknown causes. Duration of release and fire was estimated at 3 hours. Note: This compound has similar flammable properties.	Release caught fire, 4 employees/crew were noted as injured and hospitalized. All people within 0.5 mile (0.8 km) were evacuated. Three miles (4.8 km) of roadway and one mile (1.6 km) of the Trenton Channel waterway were closed during the incident.
383865 April 16, 1997 Phillips Petroleum	Hutchinson, Texas Water in line froze and split a transfer pipeline (unknown diameter), releasing 200 gallons (0.8 m^3) of normal butyl mercaptan.	No fire, injuries, hospitalizations, or fatalities, or evacuation noted at time of report.
309151 Sept 29, 1995 ELF Atochem	Carrolton, Kentucky storage facility. A disk ruptured on a tank reactor, releasing 970 pounds (440 kg) of monochlorobenzene and 3,600 pounds (1,633 kg) of tetrahydrofuran to air. Note: Provides an idea of potential release sizes from storage tanks.	
296851 June 24, 1995 ELF Atochem	Carrolton, Kentucky storage facility. Unknown causes released 200 gallons (0.8 m^3) of tetrahydrofuran to water. Spill was treated in onsite wastewater treatment system. Note: Provides an idea of potential release sizes from storage tanks.	No fire, injuries, hospitalizations, or fatalities, or evacuation noted at time of report.

4.2.6 Regulatory Setting: Applicable Safety Standards and Responsibilities

4.2.6.1 Federal and State Agency Jurisdiction and Cooperation

Federal and State agency authority and responsibilities for developing and enforcing safety requirements depend on the portion of the Project being evaluated. Agency jurisdiction and applicable safety regulations for the Project are summarized in Table 4.2.6-1.

Pipeline Safety Inspection and Enforcement

Onshore and offshore pipelines for the proposed Project would be subject to design review construction and operational safety inspections and enforcement by several federal and state agencies. Agencies shown in boldface type in Table 4.2.6-1 have primary authority (either statutory or through delegation of federal powers to a state agency through a memorandum of agreement or regulatory mandate). For example, the DOT, through RSPA OPS, has statutory authority over pipeline safety in the U.S. but has delegated that authority for intrastate utility-owned natural gas pipelines to the CPUC.

Pipelines to be operated or constructed by SoCalGas, a subsidiary of Sempra Energy and a public utility as defined in Section 216 of the California Public Utilities Code, would be under the jurisdiction of the CPUC. The CPUC conducts its pipeline safety inspection and investigation activities through its Consumer Protection and Safety Division's Safety and Reliability Branch (SRB). CPUC staff engineers conduct annual compliance audits and inspections of SoCalGas' facilities in each of their operating areas, including field testing of specific pipeline facilities. In addition, the CPUC SRB staff may inspect and monitor any construction, operations, or maintenance activity on SoCalGas' transmission or distribution system for compliance with pipeline safety regulations. (Applicable regulations are described in Subsection 4.2.6.2 under "Natural Gas Transmission Pipelines – Design and Safety Standards.") The CPUC intends to exercise its safety jurisdiction in the event that the proposed Project is approved and built and has the authority to inspect and evaluate design and construction of pipelines interconnecting with Cabrillo Port. The CPUC would provide ongoing safety oversight subsequent to construction through its comprehensive pipeline safety inspections.

Table 4.2.6-1 Lead and Cooperating Agency Authority for the Project

Facility and Purpose	General Location	Primary Implementing Agency(ies) *Key Cooperating Agencies are shown in italics*			
		Siting	**Design & Safety Regulation**	**Safety Inspections**	**Enforcement Actions**
Floating Storage and Regasification Unit (FSRU)	Offshore: Outer Continental Shelf, Federal waters	**USCG** **MARAD** *CSLC,* *MMS* *RSPA OPS*	**USCG**	**USCG**	**USCG**
Offshore Pipelines Two parallel subsea pipelines *Transfer natural gas from FSRU to shore crossing.*	Offshore; Outer Continental Shelf, Federal waters	**USCG** **MARAD** *CSLC,* *MMS* *RSPA OPS*	**RSPA OPS,** *CSLC*	**RSPA OPS,** *CSLC*, *MMS*	**RSPA OPS,** *CSLC*, *MMS*

Table 4.2.6-1 Lead and Cooperating Agency Authority for the Project

Facility and Purpose	General Location	Primary Implementing Agency(ies) *Key Cooperating Agencies are shown in italics*			
		Siting	**Design & Safety Regulation**	**Safety Inspections**	**Enforcement Actions**
Offshore Pipelines Two parallel subsea pipelines *Transfer natural gas from FSRU to shore crossing.*	Offshore; State waters within 3 NM (3.5 miles or 5.6 km) of shore	**USCG** **MARAD** **CSLC** *MMS, RSPA OPS*	**RSPA OPS, CSLC**	**RSPA OPS, CSLC**	**RSPA OPS,** *CSLC*
Shore Crossing at Ormond Beach *Connect the two subsea parallel pipelines to existing onshore infrastructure.*	Ormond Beach, Ventura County, CA	**USCG** **MARAD** **CSLC, CCC** ***RSPA OPS***	**RSPA OPS, CSLC**	**RSPA OPS, CSLC**	**RSPA OPS,** *CSLC*
Metering Station and Odorization Facility at Ormond Beach *Odorize gas; measure and transfer ownership of natural gas.*	Reliant Energy Ormond Beach Generating Station, Ventura County, CA	**CPUC SRB, CSLC, CCC,** *RSPA OPS*	**CPUC SRB,** **RSPA OPS**	**CPUC SRB,** **RSPA OPS, CSLC**	**RSPA OPS,** *CPUC SRB*
Onshore Pipelines and Facilities *Transport gas to distribution system.*	Ventura County, CA Los Angeles County, CA City of Oxnard, CA	**CPUC SRB,** *RSPA OPS, CSLC*	**CPUC SRB,** **RSPA OPS**	**CPUC SRB,** **RSPA OPS**	**RSPA OPS,** ***CPUC SRB***

BHPB = BHP Billiton (the Applicant)
CCC = California Coastal Commission
CDFG = California Dept. of Fish and Game
CPUC SRB = California Public Utilities Commission, Consumer Protection and Safety Division, Safety and Reliability Branch
MARAD = U.S. Maritime Administration
MMS = Minerals Management Service
OPS = Office of Pipeline Safety
RSPA = Research and Special Projects Administration
SoCalGas = Southern California Gas Company
USB = CPUC Utilities Safety Branch
USCG = U.S. Coast Guard

LNG Interagency Permitting Working Group

This working group was established to facilitate interagency communication and cooperation among State and local agencies that may be involved in permitting an LNG facility in California. Participating agencies with responsibilities in the areas where the proposed Project is located include the CARB, the CCC, the CEC, the CPUC, the

CSLC, the Department of Conservation, the CDFG, the Ventura County Planning Department, and the Port of Long Beach. Additional information regarding the focus and goals of this working group can be found on their website at http://www.energy.ca.gov/lng/working_group.html.

4.2.6.2 Applicable Safety Standards

Design and Safety Standards – The Process

Applicable design and safety standards for this Project would be identified as part of a process, with significant input from the Applicant as well as input (and final determination) by the responsible Federal and State agencies. As with any large, complex project, the Applicant would submit proposed design criteria (also called the "design basis") to the agencies for review and comment. The Applicant will be expected to provide very clear criteria regarding the Project design basis (e.g., presumptions regarding the seismic zone or wind load exposure zone), as well as specific sections, subsections, and effective dates of nationally and internationally recognized design codes, standards, and recommended practices that would be used for the analysis and design of each component of the Project (e.g., mooring lines, anchors, risers).

The responsible agencies would review the proposed design criteria and may modify the criteria or require additional criteria to ensure that both offshore and onshore, the Project would be designed, constructed, and operated safely. The design criteria, as modified and approved by the responsible agencies, would be included as conditions of any license or lease granted to the Applicant.

If a license or lease were granted, the Applicant would provide detailed designs based on the approved criteria. Final detailed designs can be done in a number of ways. For example, the Applicant can contract with a shipyard that will develop the final detailed designs and construct the FSRU hull. Some portions of the Project could be purchased as completed units (e.g., the Moss spheres and other structural components) that must meet the approved design criteria. The responsible agencies may have the expertise in-house to conduct detailed technical reviews of these final designs, e.g., CSLC's engineering staff would likely conduct a detailed engineering review of the subsea pipelines. With the assistance of a third-party verification agent, the USCG, in consultation with the CSLC, would evaluate the design, construction and operations of the proposed Project.

Vessel Traffic – Security and Safety Standards

Vessel traffic is regulated through a framework of overlapping international treaties and standards, national laws/regulations and local, port or area specific rules. In general, the purpose of such regulation is to prevent vessel collisions, groundings and other accidents, allow for safe operations at port facilities, provide for the security of the U.S., protect the environment, promote safety, and allow enforcement of other applicable laws. Which particular set of laws, regulations, or rules apply to a vessel is primarily a function of the vessel's position, flag of registry and intended destination, but also depends largely on the vessel's type, size, purpose, and nature of work. Further rules apply depending on weather, visibility, and other factors. It is important to note that some international treaties and United States laws allow for the temporary control of vessel movements by the USCG for the purpose of enforcing security, customs, narcotics, environmental, immigration, and other laws.

The U.S. laws and regulations that will most affect vessel traffic at and around the FSRU during operations are the Deepwater Port Act of 1974 as modified by The Maritime Transportation and Security Act of 2002. The requirements of these two bodies of law are merged in USCG regulations contained in 33 CFR 148, 149 and 150. These regulations control all aspects of Deepwater Port construction and operation, including all vessel actions within a 1,640-foot (500 m) safety zone around the FSRU. No non-Project vessel may enter this safety zone except due to forces beyond its control such as heavy weather or equipment failure. Project vessels must obtain permission of the Deepwater Port's person in charge of vessel operations prior to entry into this zone. A radar surveillance of the safety zone by the Deepwater Port is required any time a LNG carrier gives notice that it is 20 miles (37 km) out, Project vessels are under way in the safety zone, any vessel is about to enter the safety zone, or as the port's security plan requires. Starting at the 20-mile (37 km) report, the Deepwater Port's communications center passes weather reports and traffic information to the tanker throughout its transit. The proposed Project's mandatory operations plan must define the routes and speeds to be taken by LNG carriers during approach.

The USCG is responsible for the enforcement of all laws and regulations on U.S. flagged vessels on the high seas and all vessels within U.S. waters, which include all proposed Project activities with the exception of foreign construction and high seas portion of the towing for the FSRU. The FSRU will be permanently moored just within 12.2 NM (14 miles or 22.4 km) of the California coast. Thus, all vessels mooring there, declaring their intent to moor there, or transferring anything to or from the FSRU will be subject to boarding and control by the USCG for the purpose of enforcement of all laws and regulations mentioned herein. The USCG enforces the safety and security zones mentioned above, keeping unauthorized vessels out of such zones to the extent that Coast Guard resources allow. The U.S. military (including the USCG) is also allowed to take actions necessary for the protection of U.S. citizens and property from hostile acts.

After the events of 9/11, the International Maritime Organization (IMO) added Section 11-2 to the Safety of Life At Sea (SOLAS) treaty. Amongst many new security measures is the requirement for certain vessels to carry Automatic Identification Systems (AIS). An AIS is a radar transponder that provides a vessel's name, location, heading, speed, cargo and other information when struck by the radar pulse from another vessel or ground-based radar such as that used by the Vessel Traffic Service (VTS) at Los Angeles/Long Beach. This information, in addition to the traditional "blip" denoting range and bearing that a radar displays, is of great help in avoiding collisions. The Applicant has indicated that each of the LNG carriers and the FSRU will carry an AIS.

A number of these marine traffic regulations are also discussed in Subsection 4.3, "Marine Traffic." A detailed discussion is also provided in Marine Safety and Security Requirements, which is included in Appendix C to this EIS/EIR.

FSRU and LNG Carrier Vessel Standards – Certificates of Class

The Applicant has stated that class certification will be obtained for all "vessels" associated with the proposed Project, including the FSRU and each of the LNG carriers. This means that the vessels will be designed and constructed in accordance with stringent requirements defined by an independent classification society. A classification society is an industry organization, other than a flag state, that issues certificates of class and/or International Convention Certificates (see Section 2, "Project Description," for additional information about classification societies). The certificates of class are based on rules published by the classification society that govern the design and construction of ships and offshore installations. A classification society has specific procedures regarding the level of design review and survey that are required to allow a vessel to be "classified." Classification would indicate that the vessel has met applicable class rules, international requirements, and specific national requirements. Also, some flag states delegate certain additional review and inspection responsibilities to classification societies.

The rules and regulations of the above entities are broad in scope, covering almost every aspect of a vessel's (and thus the FSRU's) construction. As the FSRU and carriers are designed to carry cryogenic gases, additional regulations would govern their construction. These IMO conventions include:

- Safety of Life at Sea (SOLAS), 1974/1981;
- Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (Gas Carrier Code), 1983;
- International Code for Ships Carrying Liquefied Gases in Bulk (International Gas Carrier [IGC] Code), 1993;
- 1994/1996 Amendments to the IGC (replaced the Gas Carrier Code);
- International Convention on Standards of Training, Certification and Watchkeeping (STCW) for Seafarers, 1978; and the
- International Management Code for the Safe Operation of Ships and for Pollution Prevention (International Safety Management [ISM] Code) – adopted by IMO Resolution A.741 (18) in 1994.

Some of the major safety features required by the above entities will significantly reduce the likelihood of an accidental cargo release and will substantially mitigate any release, regardless of cause. These include requirements for double hull construction, separation of cargo holds and piping systems, accessibility for inspection access, leak detectors in hold spaces, tank requirements for cargo containment, structural analysis, secondary container and thermal management, tank construction and testing requirements, construction and testing requirements for piping and pressure vessels, emergency shutdown valves and automatic shutdown systems, loading arm emergency release couplings, pressure venting systems, vacuum protection systems, fire protection systems, and cargo tank instrumentation.

A more detailed description of these requirements is included in Marine Safety and Security Requirements, which is contained in Appendix C to this EIS/EIR.

Deepwater Port – Design and Safety Standards

With the passage of the Maritime Transportation Security Act of 2002 (MTSA) and the implementation of the Temporary Interim Rule (TIR) of 33 CFR Subchapter NN, there has been heightened interest within the energy industry in developing deepwater ports. The USCG Deepwater Ports Standards Division (G-MSO-5) is responsible for developing and maintaining regulations and standards for fixed and floating offshore facilities engaged in oil and gas importation in Federal waters. In addition to design and safety standards, the Division is responsible for related issues for the license review. The applicable regulations and standards are summarized in Table 4.2.6-2.

The CSLC's Marine Facilities Division also plans to begin a process to develop additional design guidance and criteria for LNG terminals over the coming months. It is not clear whether the guidance and criteria that will be developed will be applicable to LNG ports licensed under the Deepwater Port Act (DWPA).

Criteria applicable to vessels transporting hazardous materials, including LNG, are contained in 33 CFR Subpart NN (Parts 151 to 159), and criteria for navigation safety are in 33 CFR Subpart O (Parts 160 to 169) and Subpart P (Parts 173 to 187). The impacts associated with vessel transport are included in Section 4.3, "Marine Traffic," with a more detailed description of these requirements included in Marine Safety and Security Requirements, which is contained in Appendix C to this EIS/EIR.

Deepwater Port – Operational Measures for Accident Release Prevention

In addition to stringent design and construction standards, the FSRU and LNG carriers would be subject to the operational safety requirements contained in the DWPA. Current siting criteria and design, construction, and operational criteria applicable to the deepwater port portion of the Project are contained in a temporary interim rule issued by the USCG on January 6, 2004 (69 FR 724), which amended 33 CFR Subchapter NN (Parts 148 to 150) to include specific requirements for LNG facilities. These requirements are briefly summarized in Table 4.2.6-2 and include measures relating to training, development of formal operational procedures, and inspections.

Training requirements for crews of LNG carriers are specified in the IMO STCW Convention and those for the FSRU are detailed in 33 CFR 150. A wide variety of training is included for both, including marine firefighting, water survival, spill response and clean-up, emergency medical procedures, hazardous materials procedures, confined space entry, and training on operational procedures.

Both the FSRU and the LNG carriers would be required to have formal operating plans covering an extensive array of operational practices and emergency procedures. LNG carriers are required by the IMO to meet the ISM Code, which addresses preparing for responding to emergency situations such as fire and LNG releases. The LNG carrier's navigational, pollution response, and some emergency procedures would also be covered in the Deepwater Port Operations manual, which would address every aspect of the FSRU's operations. The minimum contents of this manual are detailed in 33 CFR 150. This manual would be required to be extremely detailed and specific, covering every conceivable contingency as well as normal operations. The operations manual must meet all requirements set forth by the USCG and be approved by that organization before operations could begin.

For the proposed Project, the USCG has the authority and jurisdiction to perform inspections of Project vessels in U.S. waters or on the high seas after a vessel states intent to moor at the deepwater port. Additional inspections may be carried out on LNG carriers by their flag states, by classification societies, and by the owners. Per 33 CFR 150, the USCG also may inspect the FSRU at any time, with or without notice, for safety, security, and compliance with applicable U.S. laws and regulations.

33 CFR 150 mandates that the FSRU be self-inspected every 12 months by the owner or operator to ensure compliance with applicable safety and security laws and regulations. The results would have to be reported to the USCG Captain of the Port (COTP) within 30 days of completion and could be verified for accuracy by a Coast Guard inspection at any time. This report would be required to include descriptions of any failure and the scope of repairs subsequently made. Any classification society certification or interim class certificate would also be required to be reported to the COTP as well.

Natural Gas Transmission Pipelines – Design and Safety Standards

The DOT pipeline standards are published in 49 CFR Parts 190-199. Part 192 of 49 CFR specifically addresses natural gas pipeline safety issues. It does not, however, address other issues such as siting and routing, bond issues, etc. These items are, in part, a matter of private negotiation between pipeline companies and landowners and/or local government zoning boards.

The CPUC, which regulates utility-owned intrastate pipelines in California, has adopted more stringent requirements than those imposed by the DOT standards. These are contained in CPUC General Order 112-E and are briefly described in Table 4.2.6-2.

Table 4.2.6-2 Major Laws, Regulatory Requirements, and Plans for Public Safety

Law/Regulation/Plan/ Agency	Key Elements and Thresholds; Applicable Permits
Federal	
Deepwater Port Act, as amended, 33 U.S.C. 1501 *et seq.*	• **Establishes the regulatory regime** for the location, ownership, construction, and operation of deepwater ports in waters beyond the territorial limits of the U.S.

Table 4.2.6-2 Major Laws, Regulatory Requirements, and Plans for Public Safety

Law/Regulation/Plan/ Agency	Key Elements and Thresholds; Applicable Permits
33 CFR 148, Subparts A and G *- USCG*	• Note: A more detailed discussion of these requirements is provided in Marine Safety and Security Requirements, contained in Appendix C to this EIS/EIR. • **Site evaluation and pre-construction testing.** Prescribes requirements for activities involved in site evaluation and pre-construction testing at potential locations and that may pose a threat to human health or welfare. • **Environmental review criteria for deepwater ports**. Defines how the Deepwater Port Act interacts with other Federal and State laws; requires construction plan to incorporate best available technology and industry practices. Defines general design, construction, and operational criteria for deepwater ports.
33 CFR 149, Subpart s A, B, D, E, and F *- USCG*	• Note: A more detailed discussion of these requirements is provided in Marine Safety and Security Requirements, contained in Appendix C to this EIS/EIR. • **Deepwater Ports: Design, Construction, and Equipment.** • Describes the process for submitting alterations and modifications affecting the design and construction of a deepwater port. • **Pollution prevention equipment.** Defines requirements for discharge containment, valves, monitoring and alarm systems, and communications equipment. • **Firefighting and fire protection equipment**. Defines minimum requirements for firefighting equipment, detection and alarm systems. • **Aids to navigation**. Prescribes requirements for lighting, marking, and sound signals. • **Safety-related design and equipment**. Prescribes requirements for construction and design standards and specifications for safety-related equipment and systems.
49 CFR 173 and 177 *- RSPA OPS*	• **Transportation of hazardous materials in portable tanks and by highway.** • **Specifies minimum requirements for portable tanks and cargo tank motor vehicles.** • Specifies requirements for driver training, inspections, shipping papers, segregation of hazardous materials, • Requires engine shutoff and bonding and grounding between containers to prevent accidental ignition due to static electricity for **Class 3 materials (flammable and combustible liquids)**.
33 CFR 150, Subparts A, B, C, D, E, F, H, J *- USCG*	• Note: A more detailed discussion of these requirements is provided in Marine Safety and Security Requirements, contained in Appendix C to this EIS/EIR. • **Deepwater Ports: Operations.** • **Operations Manuals**. Defines requirements for Operations Manuals. • **Inspections.** Defines requirements for deepwater port inspections, including annual self-inspection and notification requirements upon receipt of classification society certifications. • **Personnel.** Describes requirements for ensuring personnel are qualified. • **Vessel navigation.** Describes requirements for radar surveillance, tanker advisories, rules of navigation.

Table 4.2.6-2 Major Laws, Regulatory Requirements, and Plans for Public Safety

Law/Regulation/Plan/ Agency	Key Elements and Thresholds; Applicable Permits
	• **Cargo transfer operations**. Describes requirements for inspection and testing of cargo transfer systems and for allowing or stopping cargo transfers. • **Operations (Emergency Equipment).** • **Aids to navigation**. Prescribes required inspection and testing. • **Safety zones, no anchoring areas, and areas to be avoided**.
Pipeline Safety Act of 1994 49 U.S. Code (U.S.C.) 60101, *et seq.*	• Defines the framework for pipeline safety regulation in the U.S.
Pipeline Safety Improvement Act (PSIA) of 2002, P.L. 107-355, 49 U.S.C. 60101, *et seq.* *- RSPA OPS, CSLC, CPUC*	• **Tightens federal inspection and safety requirements** to include mandatory inspections of oil and natural gas pipelines with a history of safety problems within the next five years, with all pipelines to be inspected within ten years. All pipelines will then be inspected at 7-year intervals. • **Corrective actions**, including physical inspection, testing, repair, or replacement can be ordered by RSPA OPS. • **Pipeline integrity management programs** must be developed and implemented by pipeline operators, which includes identifying areas where risks may be greater due to the population density (high consequence areas) and implementing a series of actions to mitigate the potential hazards in these areas. • **Emphasizes the One-call notification system** and encourages pipeline operators to voluntarily adopt and implement best practices for notification of leaks and ruptures. • **Public education programs** must be established by pipeline operators to provide municipalities, schools, and other entities with information to prevent pipeline damage and to prepare for any pipeline emergencies, including the one-call notification system, possible hazards from accidental releases from a pipeline, and actions to take in the event of a release. • **Coordinated environmental review and permitting process** is defined to expedite conducting any necessary pipeline repairs. • **Maximum civil penalties** that can be assessed against pipeline operators for violations of pipeline safety standards have increased. • **Whistleblower Protections.** The PSIA significantly strengthens the enforcement of pipeline safety laws and includes specific protections for employees who provide information to the federal government about pipeline safety. • **Mandates continued federal pipeline safety research and development** by the National Institute of Standards and Technology, Department of Transportation, and Department of Energy.
49 CFR 190 *- RSPA OPS*	• **Pipeline Safety Programs and Procedures**. Describes availability of informal guidance and interpretive assistance and establishes framework for inspections and for safety enforcement actions.

Table 4.2.6-2 Major Laws, Regulatory Requirements, and Plans for Public Safety

Law/Regulation/Plan/ Agency	Key Elements and Thresholds; Applicable Permits
49 CFR 191 *- RSPA OPS, CSLC, CPUC*	• **Annual reports, incident reports, and safety-related condition reports.**
49 CFR 192 *- RSPA OPS, CSLC, CPUC*	• **Minimum Federal safety standards** for transportation of natural gas and other gases, including minimum materials properties such as yield strength; design formulas; standards for valves, flanges, fittings, supports and anchors; pipeline pressure controls; welding requirements; installation designs and limitations; corrosion control and monitoring; testing and inspection requirements; remedial and repair measures; environmental protection and safety requirements; procedural manuals for operations, maintenance, and emergencies; damage prevention programs; incident investigation; gas odorization; and requirements for abandonment or deactivation of facilities. • **Pipeline Integrity Management Programs** for high consequence areas are described in Subpart O to this Part. • **Changes to public education requirements** have been proposed (69 FR 35279, June 24, 2004) to require pipeline operators to develop and implement public education programs based on the provisions of the American Petroleum Institute's (API) recommended practice (RP) 1162, "Public Awareness Programs for Pipeline Operators."
49 CFR 199 *- RSPA OPS, CSLC, CPUC*	• **Drug and alcohol testing,** which requires pipeline operators to test covered employees as well as contractor employees for the presence of prohibited drugs and alcohol.
Emergency Planning and Community Right-to-Know Act (EPCRA) 40 CFR 355 App. A	• **Not applicable for the major chemical use associated with the LNG facility and pipeline operation;** neither methane, urea, nor the chemicals proposed to be used to odorize the natural gas are listed as hazardous or extremely hazardous substances under this statute. Chemical use during construction activities may trigger reporting for some chemicals.
Clean Air Act (CAA) Section 112(r), Risk Management Program 40 CFR 68	• **Not applicable.** The natural gas pipelines are not a "stationary source." No major use on the FSRU of extremely hazardous substances as defined under EPCRA.
State	
- CSLC	• **Design Criteria and Standards.** CSLC's Marine Facilities Division is currently developing design criteria and evaluating industry standards that will apply to LNG terminals in California. It is unclear at this time whether the proposed Project will be subject to these requirements.
CSLC Regulations, Article 3.3 – Oil and Gas Production Regulations, Section 2132 (h) – Pipeline Operations and Maintenance. *- CSLC*	• **Pipeline Operation and Maintenance Requirements.** Specifies minimum requirements for all oil and gas pipelines on State tide and submerged lands, including general requirements for written procedures, controls on maximum operating pressures, communications, external and internal corrosion control, pipeline inspections, inspection reports, and safety equipment and procedures,

Table 4.2.6-2 Major Laws, Regulatory Requirements, and Plans for Public Safety

Law/Regulation/Plan/ Agency	Key Elements and Thresholds; Applicable Permits
- CSLC	• **Seismic Standards for Pipelines. CSLC requires compliance with the following guidance:** 1. "Guidelines for the Design of Buried Steel Pipe," American Lifeline Alliance, July 2001. 2. "Draft Guideline for Assessing the Performance of Oil and Natural Gas Pipeline Systems in Natural Hazard and Human Threat Events," American Lifeline Alliance, April 2004. 3. "Guidelines for the Seismic Design of Oil and Gas Pipeline Systems," American Society of Civil Engineers, 1984.
California Public Utilities Commission General Order 112-E *- CPUC*	• **CPUC General Order 112-E**, "State of California Rules Governing Design, Construction, Testing, Operation, and Maintenance of Gas Gathering, Transmission, and Distribution Piping Systems" prescribes rules that must be followed in addition to Federal pipeline safety standards. • **Reporting.** Public utilities operating pipelines in California (in this case, SoCalGas) must notify the CPUC of any pipeline incident or safety-related condition that must be reported to RSPA OPS under federal regulations. They must also report incidents to the CPUC that would not trigger reporting under Federal rules, e.g., for gas releases with property damage of more than $1,000 and for any incident that involved fire, explosion, or underground dig-ins. • **Engineering design review.** Engineering design information must be submitted to the CPUC in advance of any change in maximum allowable operating pressure, or construction, reconstruction, or reconditioning of an existing pipeline.
California Accidental Release Program (Cal ARP)	• **Not applicable.** The natural gas pipelines are not a "stationary source." Chemicals proposed to be stored at the onshore odorization facility are neither extremely hazardous substances as defined under EPCRA nor are they regulated substances in California.

As part of its application, the Applicant would be expected to certify that the pipelines and aboveground facilities associated with the Project will be designed, constructed, operated, and maintained in accordance with or to exceed the DOT Minimum Federal Safety Standards contained in 49 CFR Part 192. These regulations, which are intended to protect the public and prevent natural gas facility accidents and failures, include specifications for material selection and qualification; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion. The DOT regulations also incorporate by reference the additional codes and standards shown below in Table 4.2.6-3.

The onshore portions of this Project owned and operated by SoCalGas would be required to meet Federal pipeline regulations contained in 49 CFR 190, 191, 192, and 199 as well as additional State requirements contained in CPUC's General Order 112-E, State of California Rules Governing Design, Construction, Testing, Operation, and Maintenance of Gas Gathering, Transmission, and Distribution Piping Systems (California Public Utilities Commission 1996).

Table 4.2.6-3 Documents Incorporated by Reference into Title 49 CFR Part 192 (Part 192, Appendix A, as amended through June 14, 2004)

		Title (applicable edition)
A.	**American Gas Association (AGA)**	
(1)	AGA Pipeline Research Committee, Project PR-3-805	A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (AGA-PR3-805-1989).
B.	**American Petroleum Institute (API)**	
(1)	API Specification 5L	Specification for Line Pipe (42nd edition, 2000).
(2)	API Recommended Practice 5L1	Recommended Practice for Railroad Transportation of Line Pipe (4th edition, 1990).
(3)	API Recommended Practice 5LW	Transportation of Line Pipe on Barges and Marine Vessels (2nd edition, 1996)
(4)	API Specification 6D	Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves) (21st edition, 1994).
(5)	API Standard 1104	Welding of Pipelines and Related Facilities (19th edition, 1999, including its October 31, 2001 errata).
C.	**American Society for Testing and Materials (ASTM)**	
(1)	ASTM Designation A 53/A53M-99b	Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless (ASTM A53/A53M-99b).
(2)	ASTM Designation A 106	Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service (ASTM A106-99).
(3)	ASTM Designation A 333/A 333M	Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service (ASTM A333/A333M-99).
(4)	ASTM Designation A 372/A 372M	Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels (ASTM A372/A372M-1999).
(5)	ASTM Designation A 381	Standard Specification for Metal-Arc-Welded Steel Pipe for Use With High-Pressure Transmission Systems (ASTM A381-1996).
(6)	ASTM Designation A 671	Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures (ASTM A671-1996).
(7)	ASTM Designation A 672	Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures (ASTM A672-1996).
(8)	ASTM Designation A 691	Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures (ASTM A691-1998).
(9)	ASTM Designation D638	Standard Test Method for Tensile Properties of Plastics (ASTM D638-1999).
(10)	ASTM Designation D2513-1987 applies to §192.283(a)(1)	Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing and Fittings (ASTM D2513-1987).

Table 4.2.6-3 Documents Incorporated by Reference into Title 49 CFR Part 192 (Part 192, Appendix A, as amended through June 14, 2004)

		Title (applicable edition)
(11)	ASTM Designation D2513-1999	Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing and Fittings (ASTM D2513-1999).
(12)	ASTM Designation D 2517	Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings (D 2517-2000).
(13)	ASTM Designation F1055	Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing (F1055-1998).
D.	**The American Society of Mechanical Engineers, International (ASME) and American National Standards Institute (ANSI)**	
(1)	ASME/ANSI B16.1	Cast Iron Pipe Flanges and Flanged Fittings (ASME B16.1-1998).
(2)	ASME/ANSI B16.5	Pipe Flanges and Flanged Fittings (ASME/ANSI B16.5-1996, including ASME B16.5a-1998 Addenda).
(3)	ASME/ANSI B31G	Manual for Determining the Remaining Strength of Corroded Pipelines (ASME/ANSI B31G-1991).
(4)	ASME/ANSI B31.8	Gas Transmission and Distribution Piping Systems (ASME/ANSI B31.8-1995).
(5)	ASME/ANSI B31.8S	Supplement to B31.8 on Managing System Integrity of Gas Pipelines (ASME/ANSI B31.8S-2002)
(6)	ASME Boiler and Pressure Vessel Code, Section I	Rules for Construction of Power Boilers (ASME Section I-1998).
(7)	ASME Boiler and Pressure Vessel Code, Section VIII, Division 1	Rules for Construction of Pressure Vessels (ASME Section VIII, Division 1-2001).
(8)	ASME Boiler and Pressure Vessel Code, Section VIII, Division 2	Rules for Construction of Pressure Vessels: Alternative Rules (ASME Section VIII Division 2-2001).
(9)	ASME Boiler and Pressure Vessel Code, Section IX	Welding and Brazing Qualifications (ASME Section IX-2001).
E.	**Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS)**	
(1)	MSS SP44-96	Steel Pipe Line Flanges (MSS SP-44-1996 including 1996 errata).
F.	**National Fire Protection Association (NFPA)**	
(1)	NFPA 30	Flammable and Combustible Liquids Code (NFPA 30-1996).
(2)	ANSI/NFPA 58	Standard for the Storage and Handling of Liquefied Petroleum Gases (NFPA 58-1998).
(3)	ANSI/NFPA 59	Standard for the Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants (NFPA 59-1998).
(4)	ANSI/NFPA 70	National Electrical Code (NFPA 70-1996).

Table 4.2.6-3 Documents Incorporated by Reference into Title 49 CFR Part 192 (Part 192, Appendix A, as amended through June 14, 2004)

		Title (applicable edition)
G.	**Plastics Pipe Institute (PPI)**	
(1)	PPI TR-3/2000	Policies and Procedures for Developing Hydrostatic Design Bases (HDB), Pressure Design Bases (PDB), and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials (PPI TR-3/2000-Part E only, "Policy for Determining Long Term Strength (LTHS) by Temperature Interpolation."
H.	**National Association of Corrosion Engineers International (NACE)**	
(1)	NACE Standard RP-0502-2002	Pipeline External Corrosion Direct Assessment Methodology (NACE RP-0502-2002).
I.	**Gas Technology Institute (formerly Gas Research Institute (GRI)**	
(1)	GRI 02-0057	Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology (GRI 02/0057-2002).

Offshore pipelines that are installed where mean low tide water depths are less than 12 feet (3.66 m) must have a minimum cover of 36 inches (0.914 m) in soil or 18 inches (0.5 m) in consolidated rock. Where mean low tide water depths are between 12 feet (3.7 m) and 200 feet (60 m), current regulations require only that the top of the pipe be below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by some other equivalent means. RSPA OPS has promulgated more stringent cover requirements for offshore pipelines installed in shallow water in the Gulf of Mexico but has not expanded these requirements to offshore California, in part because the more stringent seismic design criteria in this area already require a more robust pipeline than is typically seen in Gulf waters. As another example, under 49 CFR 192.615, each pipeline operator must establish an emergency plan that includes procedures for minimizing the hazards in a natural gas pipeline emergency. Key elements of the plan include procedures for:

- Receiving, identifying, and classifying emergency events, gas leaks, fires, explosions, and natural disasters;
- Establishing and maintaining communications with local fire, police, and public officials, as well as coordinating emergency response;
- Making personnel, equipment, tools, and materials available at the scene of an emergency;
- Protecting people first and then property and making them safe from actual or potential hazards; and
- Implementing emergency shutdown (ESD) of the system and safely restoring service.

49 CFR 192 also requires each operator to establish and maintain a liaison with the appropriate fire, police, and public officials to learn the resources and responsibilities of

each organization that may respond to a natural gas pipeline emergency and to coordinate mutual assistance.

Pipeline Area Classifications

Minimum standards for pipeline safety are more stringent where there is a potential for greater impacts on human health and safety. Pipeline area classifications are defined in 49 CFR 192.5 and are based on an estimate of the population density in the vicinity of the pipeline. Population densities are estimated based on the number of buildings intended for human occupancy. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy. Class location units are onshore areas that extend 220 yards (200 m) on either side of the centerline of any continuous 1-mile (1.6 km) length of pipeline. The definitions for pipeline area classifications are shown in Table 4.2.6-4.

Table 4.2.6-4 Definitions of Pipeline Location Classifications

Pipeline Location Class	Pipeline Location Class Definition
Class 1	An offshore area or any class location unit with 10 or fewer buildings intended for human occupancy;
Class 2	Any class location unit with more than 10 but fewer than 46 buildings intended for human occupancy;
Class 3	Any class location unit with 46 or more buildings intended for human occupancy or an area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12- month period. (The days and weeks need not be consecutive.)
Class 4	Any class location unit where buildings with four or more stories aboveground are prevalent.

Class locations representing more populated areas require higher safety factors in pipeline design, testing, and operation. The following paragraphs provide examples of how pipeline area classification is used to ensure that more stringent standards are met in areas where there are greater potential impacts on public safety.

Pipeline area class locations are used to specify the maximum spacing allowed between sectionalizing block valves, which are used to isolate portions of the line to allow maintenance and are essential to limiting the amount of gas that can be released in the event of a leak or rupture along the pipeline. Regulations contained in 49 CFR 192.179 require every point on a natural gas transmission pipeline to be within a minimum of 10 miles (16 km) of a sectionalizing block location in Class 1 locations, within 7.5 miles (12 km) in Class 2 locations, within 4 miles (6.4 km) in Class 3 locations, and within 2.5 miles (4 km) in Class 4 locations. For onshore segments, the valve and operating device must also be readily accessible and protected from tampering and damage.

Pipe-wall thickness and pipeline design pressures, hydrostatic test pressures, maximum allowable operating pressure (MAOP), inspection and testing of welds, and frequency of pipeline patrols and leak surveys must all conform to higher standards in more populated areas. Additional information on operation and maintenance procedures applicable to the proposed pipeline, including inspection procedures, is provided in 49 CFR 192, Subparts L and M.

Minimum Standards for Pipeline Operation, Inspection, and Maintenance

DOT regulations contained in 49 CFR 192 Subparts L and M also prescribe minimum standards for installation, operating, inspecting, and maintaining pipeline facilities without regard to the pipeline area classification. For example, at the installation site, the Applicant and SoCalGas will ensure that each length of pipe and other components are visually inspected to determine that the component has not sustained any visually detectable damage that might impair its serviceability (e.g., a dent) and will ensure that repairs (e.g., by grinding or removal of cylindrical sections) of a damaged pipe are conducted in accordance with prescribed procedures.

Regulations contained in 49 CFR 192 Subpart I (Sections 192.455 – 192.491) requiring external, internal, and atmospheric corrosion control and remediation measures for corrosion also apply to all pipelines.

49 CFR 192 Part O: Pipeline Integrity Management and High Consequence Areas

Largely in response to natural gas pipeline ruptures near Carlsbad, New Mexico, and the rupture of the Olympic Pipeline near Bellingham, Washington, Congress enacted the Pipeline Safety Improvement Act of 2002 (PSIA). This act, which applies to pipeline facilities that transport natural gas or hazardous liquids in interstate commerce,

- Tightened federal inspection and safety requirements;
- Permits the DOT to order corrective actions on pipeline facilities including physical inspection, testing, repair, or replacement; increases the statutory civil penalties (i.e., the fines that can be imposed) for safety violations;
- Reaffirms and encourages operators to implement best management practices for the One-Call notification program;
- Mandates that pipeline facilities establish public education programs on the use of the One-Call system, on possible hazards from unintended releases from a pipeline facility, and on actions to take in the event of a release;
- Defines a structure for coordinated environmental reviews for pipeline repairs; directs additional research and development be conducted to ensure pipeline safety; and
- Includes whistleblower protection that prohibits pipeline operators from firing or taking adverse action against an employee for providing information to the employer or to the federal government regarding pipeline safety.

The DOT recently revised regulations contained in 49 CFR 192 to reflect changes required by the PSIA that require operators to develop integrity management programs for gas transmission pipelines located where a leak or rupture could do the most harm, i.e., where a gas transmission pipeline could impact a high consequence area (HCA). The final rule—49 CFR Part 192, Subpart O, Pipeline Integrity Management—was issued on December 15, 2003 (68 CFR 69778) and took effect on January 14, 2004. Several corrected versions of the rule were issued during the spring of 2004 (69 FR 2307, 69 FR 18228, 69 FR 21975, and 69 FR 29903). Part 192 was reformatted to combine integrity management requirements in SubPart O, Sections 192.901 – 192.951, with specific guidance added in a new Appendix E, “Guidance on Determining High Consequence Areas and on Carrying Out Requirements in the Integrity Management Rule.” These requirements are intended to increase the safety of gas transmission pipelines by requiring that each operator:

(a) Develop and implement a comprehensive integrity management program for pipeline segments where a failure would have the greatest impact on the public or property;

(b) Identify and characterize applicable threats to pipeline segments that could impact a high consequence area;

(c) Conduct a baseline assessment and periodic reassessments of these pipeline segments;

(d) Mitigate significant defects discovered from the assessment; and

(e) Continually monitor the effectiveness of its integrity program and modify the program as needed to improve its effectiveness.

These new requirements apply only to gas transmission pipelines and do not currently apply to gas-gathering or gas-distribution pipelines.

Pipeline operators are required to determine which segments of a pipeline facility must be covered under the new integrity management program requirements, based on determining the locations of HCAs. The following definitions are important to understanding how HCAs are determined:

Identified site means each of the following areas:

(a) An outside area or open structure that is occupied by 20 or more persons on at least 50 days in any 12-month period. (The days need not be consecutive.) Examples include but are not limited to beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility); or

(b) A building that is occupied by 20 or more persons on at least five days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.) Examples include but are not limited to religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks); or

(c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

Potential impact circle is a circle of radius equal to the potential impact radius (PIR).

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. The formula shown below for the PIR was developed by C-FER Technologies (C-FER) under contract with the Gas Research Institute (GRI) (Gas Research Institute 2000) and was based on a technical approach that included three parts:

(1) A fire model that relates the rate of gas release to the heat intensity of the fire,

(2) An effective release rate model that provides a representative steady-state approximation of the actual transient release rate, and

(3) A heat intensity threshold that establishes the sustained heat intensity level above which the effects on people and property are consistent with the adopted definition of an HCA.

C-FER's release and fire modeling presumed a double-ended guillotine pipeline break, with a release of natural gas contributing to an initial fireball and subsequent trench fire. The C-FER PIR for a release of 100% methane and an HCA threshold heat intensity of 5,000 BTU/hr-ft^2 has been incorporated into pipeline safety regulations at 49 CFR 192.903 and is determined by using the following formula:

$$r = 0.69 \sqrt{pd^2}$$

where:

r is the radius of a circular area in feet surrounding the point of failure,

p is the maximum allowable operating pressure (MAOP) in the pipeline segment in psi, and

d is the nominal diameter of the pipeline in inches.

HCAs must be determined using one of two allowable methods described in 49 CFR 192.903, using the process for identification described in 49 CFR 192.905 and guidance provided in an advisory bulletin (68 FR 42456, July 17, 2003). Figures 4.2.6-1 and 4.2.6-2 illustrate how HCAs are determined using each of these methods. The length of the pipeline subject to pipeline integrity assessments and mitigation actions – the pipeline section encompassed by the HCA – is also shown in these figures.

Where a potential impact circle is calculated using either Method 1 or Method 2 to establish an HCA, the length of the HCA extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy.

The regulations also allow operators to prorate the number of buildings within an impact circle until 2006. This exemption was intended to relieve the data collection burden on operators of existing pipelines but should not be applied to the new pipeline construction proposed for this Project. Pipeline operators are not required to use the same method along the entire length of any pipeline. The PIRs for the proposed pipelines and alternate routes are summarized in Table 4.2.6-5.

Table 4.2.6-5 Potential Impact Radius for Project Pipeline Routes

Pipeline Segment(s)	Nominal Pipe Diameter Inches (meters)	MAOP Psi (kg/m²)	Potential Impact Radius** Feet (meters)
Proposed Project			
Center Road Pipeline*	36 (0.9)	1,100 (773,400)	824 (251)
Line 225 Pipeline Loop	30 (0.76)	756 (531,500)	569 (174)
Alternative Deepwater Port			
Santa Barbara Channel/ Mandalay Shore Crossing/ Gonzales Road Pipeline	36 (0.9)	1,100 (773,400)	824 (251)
Alternative Shore Crossings			
Arnold Road Shore Crossing/Arnold Road Pipeline Alternative	36 (0.9)	1,100 (773,400)	824 (251)
Point Mugu Shore Crossing/Casper Road Pipeline Alternative	36 (0.9)	1,100 (773,400)	824 (251)
Alternative Onshore Pipeline Routes			
Center Road Pipeline Alternative 1*	36 (0.9)	1,100 (773,400)	824 (251)
Center Road Pipeline Alternative 2*	36 (0.9)	1,100 (773,400)	824 (251)
Line 225 Pipeline Loop Alternative	30 (0.76)	756 (531,500)	569 (174)

*Same for both Cabrillo Port and Santa Barbara Channel FSRU locations

**C-FER original document uses a factor of 0.685, which has been rounded up to 0.69 in the regulatory definition contained in 49 CFR 192. PIRs calculated for this table are based on the regulatory definition.

psi = pounds per square inch, kg/m^2 = kilograms per square meter

Method 1. HCAs are defined in 49 CFR 192.903 as an area defined as:

(i) A Class 3 location, or (ii) A Class 4 location, or

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy (unless the exception in paragraph 4 applies), or

(iv) The area within a potential impact circle containing an identified site.

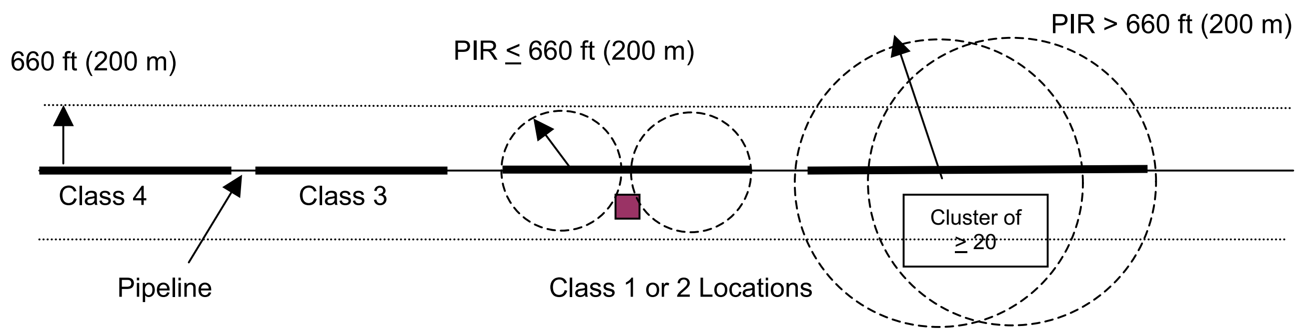


Figure 4.2.6-1 Example High Consequence Areas using Method 1

Method 2. The area within a potential impact circle containing:

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or

(ii) An identified site.

Paragraph (4) Exception: If the radius > 660 feet (200 m), the HCA may be identified based on a prorated number of buildings intended for human occupancy within 660 ft from the centerline of the pipeline until December 17, 2006. This exception was not intended for use for new pipelines.

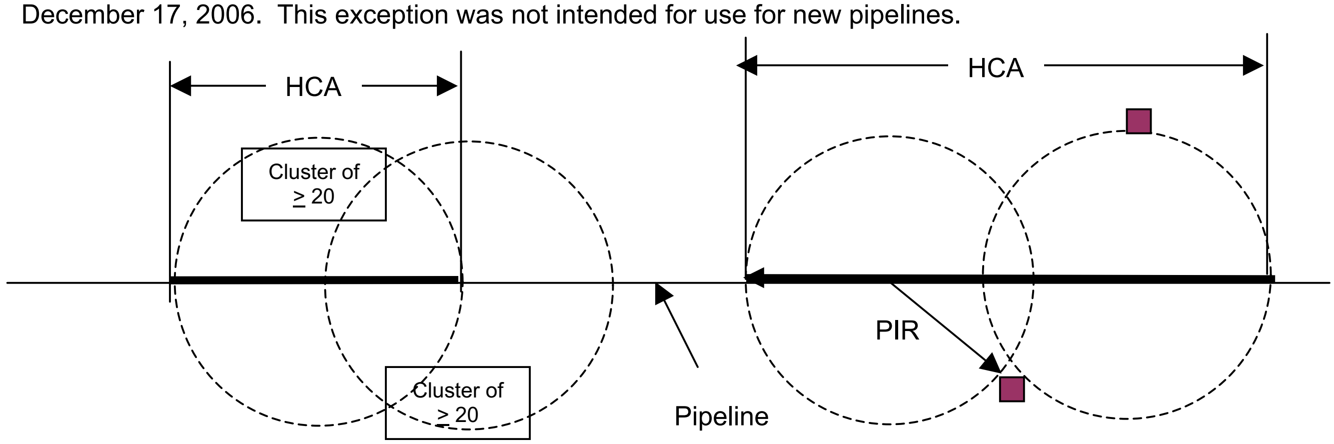


Figure 4.2.6-2 Example High Consequence Areas using Method 2

Preliminary identification of HCAs along the proposed pipeline and alternate routes is summarized in Table 4.2.6-6. This table represents a compilation of potential HCA locations drawn from the following sources:

- Sites identified by the Applicant within a 1,000-foot (305 m) PIR for the Oxnard pipelines, including the Center Road Pipeline and its two Alternatives, and within a 660-foot (201 m) radius for the Santa Clarita pipelines, which include the Line 225 Loop Pipeline and its Alternative. (Note that these PIRs were based on what were then proposed regulations. Subsequent analyses by the Applicant for other pipeline routes more closely reflected the final regulatory rule. These sites were not reevaluated, since they capture a larger area than the smaller "final rule" PIRs shown in Table 4.2.6-5);
- Sites identified by the Applicant within an 818-foot (249 m) PIR for the Arnold Road Shore Crossing/Arnold Road Pipeline and the Point Mugu Shore Crossing/Casper Road Pipeline and within a 565-foot (172 m) PIR for the Line 225 Loop Pipeline and its Alternative. (Note that the Applicant calculated these PIRs based on the C-FER document, which used a factor of 0.685 in the PIR equation. The equation contained in 49 CFR 192 rounded this factor to 0.69. PIRs shown in Table 4.2.6-5 were calculated using the regulatory definition, which produces values that are a few feet larger than the values calculated by the Applicant);
- Areas identified by the Applicant where 20 or more buildings intended for human occupancy were identified within a PIR of 818 feet (249 m) for the Center Road Pipeline or its two Alternatives, the Arnold Road Shore Crossing/Pipeline and the Point Mugu Shore Crossing/Casper Road Pipeline, and those identified within a 565-foot (172 m) PIR for the Line 225 Loop Pipeline and its Alternative;
- Outdoor areas identified as a result of developing land use and recreation information that appear to meet the criteria to be considered an "identified site" and that were located within a PIR of 824 feet (251 m) from the Center Road Pipeline or its two alternatives, the Arnold Road Shore Crossing/Arnold Road Pipeline and Point Mugu Shore Crossing/Casper Road Pipeline, or the Santa Barbara Channel/ Mandalay Shore Crossing/ Gonzales Pipeline; or within 569 feet (174 m) of the Line 225 Pipeline Loop and its Alternative; and
- Any area where the onshore pipeline is carrying unodorized natural gas.

Table 4.2.6-6 Preliminary Identification of High Consequence Areas on Project Pipeline Routes

Milepost Range	Pipeline Class per 49 CFR 192.905	HCA Milepost Range	HCA Method	Criteria Triggering HCA*
Proposed Project				
Center Road Pipeline: Potential Impact Radius = 824 ft (251 meters)				
Low tide mark to 7.6	Class 1	Low tide mark to 0.0 0.0 to 0.15	1	Site: Shore crossing, outdoor area within <750 feet (229 m) of pipeline, carrying unodorized gas.
		~4.1	1	Sites: Mobile Home park, outdoor area Density: Less Robust Housing and ≥ 20 BIHO
7.6 to 8.6	Class 3	--		
8.6 to 9.2	Class 1	--		
9.2 to 9.6	Class 3	--		
9.6 to 14.3	Class 1	13.45 to 13.75	1	Site(s)
Line 225 Pipeline Loop: Potential Impact Radius = 569 ft (174 m)				
0.0 to 0.6	Class 1	--		
0.6 to 7.1	Class 3	1.59 to 2.45	1	Density ≥ 20 BIHO
		3.53 to 3.93	1	Density ≥ 20 BIHO
		5.0 to 5.54	1	Density ≥ 20 BIHO
7.1 to 7.71	Class 1	--		
Alternative Deepwater Port				
Santa Barbara Channel/ Mandalay Shore Crossing/ Gonzales Road Pipeline Alternative*				
Low tide mark to ~3.0	Class 1	Low tide mark to 0.0 0.0 to 0.15	1	Site: Shore crossing, outdoor areas within <750 feet (229 m) of pipeline (McGrath State Beach), carrying unodorized gas.
~3.0 to ~6.5	Class 3	~3.0 to ~6.5 3.0 3.8 4.2 5.6 6.0 6.6	1	Density ≥ 20 BIHO Site(s)
~6.5 to 6.7 (junction w/Center Road Pipeline Alt 1 at MP 8.0)	Class 1	--		

Table 4.2.6-6 Preliminary Identification of High Consequence Areas on Project Pipeline Routes

Milepost Range	Pipeline Class per 49 CFR 192.905	HCA Milepost Range	HCA Method	Criteria Triggering HCA*
Alternative Shore Crossings				
Arnold Road Shore Crossing/ Arnold Road Pipeline Alternative				
Low tide mark to 1.5 (junction with Center Road Pipeline at MP 1.8)	Class 1	Low tide mark to 0.0 0.0 to 0.15	1	Site: Shore crossing, outdoor area within <750 feet (229 m) of pipeline, carrying unodorized gas.
		--		
Point Mugu Shore Crossing/Casper Road Pipeline Alternative				
Low tide mark to 1.5 (junction with Center Road Pipeline at MP 2.5)	Class 1	Low tide mark to 0.0	1	Site: Shore crossing, outdoor area within <750 feet (229 m) of pipeline, carrying unodorized gas.
Alternative Onshore Pipeline Routes				
Center Road Pipeline Alternative 1 **Potential Impact Radius = 824 ft (251 m)** (Note: BHPB 2003)				
0.0 to 1.4	Class 1	1.3 to 1.4	1	Density ≥ 20 BIHO
1.4 to 3.3	Class 3	1.4 to 3.3 1.75 to 2.35 2.65 to 3.15	1	Density ≥ 20 BIHO Site(s) Site(s) Site(s)
3.3 to 5.3	Class 1	4.0 4.1	1	Site(s) Site(s)
5.3 to 9.5	Class 3	6.95 to 7.25 7.65 to 9.15 8.1 to 9.5	1	Site(s) Site(s) Density ≥ 20 BIHO Site(s)
9.5 to 10.0	Class 1	--		
10.0 to 11.3	Class 2	10.25 to 10.55	1	Site(s)
11.3 to 15.0	Class 1	14.15 to 14.45	1	Site(s)
Center Road Pipeline Alternative 2 (Note: BHPB 2003)				
0.0 to 1.4	Class	1.3 to 1.4	1	Density ≥ 20 BIHO

Table 4.2.6-6 Preliminary Identification of High Consequence Areas on Project Pipeline Routes

Milepost Range	Pipeline Class per 49 CFR 192.905	HCA Milepost Range	HCA Method	Criteria Triggering HCA*
1.4 to 3.3	Class 3	1.4 to 3.7 1.75 to 2.35 2.65 to 3.15	1	Density ≥ 20 BIHO Site(s) Site(s)
3.3 to 3.6	Class 2	--		
3.6 to 12.6	Class 1	10.65 to 10.95	1	Site(s)
Line 225 Pipeline Loop Alternative				
0.0 to .0.6	Class 1	--		
0.6 to 5.4	Class 3	1.59 to 2.45 3.53 to 3.93 4.8 to 5.35	1	Density ≥ 20 BIHO Density ≥ 20 BIHO Density ≥ 20 BIHO
5.4 to 5.7	Class 1	--		
5.7 to 6.6	Class 3	--		
6.6 to 7.22	Class 1	--		

BIHO = Building Intended for Human Occupancy

* Pipeline Class and HCA housing density estimated from general, not detailed maps; to be refined. Identification of specific sites, e.g., MP locations of schools, hospitals, care facilities, is not included in this table due to SSI concerns.

Sensitive receptor site information provided by the Applicant was checked against similar information provided in the July 2004 Crystal Energy LLC Environmental Assessment for the Line 225 Loop pipeline. Sites (schools, hospitals, and parks only) for the Santa Barbara/Mandalay Shore Crossing/Gonzales Pipeline were identified from maps contained in the July 2004 Crystal Energy, LLC Environmental Assessment.

Natural Gas Odorization Facility – Safety Standards

Odorant gases are generally transported and stored in liquid form in pressurized tanks that must meet specific federal design, construction, and maintenance requirements imposed by the DOT. Operational safety, inspection, maintenance, and transfer practices for these flammable gases must also meet specific and stringent requirements imposed by the California Division of Occupational Safety and Health (CalOSHA).

Natural gas odorants are considered hazardous materials under the U.S. Occupational Safety and Health Administration (OSHA) Hazard Communication Standard (worker right-to-know) regulations contained in 29 CFR 1910.1200, which triggers requirements for physical and health hazard information to be provided in a MSDS to workers who use or may be exposed to these chemicals. Although odorants present a potential fire and explosion hazard, the chemical components of the odorants are not toxic and do not generally pose a threat to public health.

Regulations promulgated by the USEPA under EPCRA require annual reporting of hazardous materials listed in 40 CFR 302.4 that have been "released"—which also means stored and/or used in amounts greater than a threshold planning quantity—to local and state agencies. EPCRA also requires immediate reporting of accidental releases of hazardous substances in excess of a reportable quantity. The information collected under the EPCRA Tier II and Toxic Release Inventory (TRI) reporting requirements is then made available to the public. The odorant gas proposed to be added to the natural gas shipped in the onshore pipeline is Spotleak 1039, which is a 50/50 mixture of tert-butylmercaptan (CAS 75-66-1) and tetrahydrothiophene (CAS 110-01-0). Neither of these compounds is included on the list of reportable chemicals under EPCRA due to toxicity. Because the odorant mixture is highly flammable, however, accidental releases of 100 pounds (45.4 kg) or more of this material must be reported immediately to the National Response Center.

4.2.7 Significance Criteria

Levels of risk that are "significant" to members of the public can be difficult to define and often vary widely, depending upon public perception and how close a proposed Project would be to the places where an individual lives, works, and recreates. That is a principal reason that public involvement is such an important part of the Project evaluation process. As described in other parts of this section, the term "risk" reflects both the probability of an incident occurring (the frequency) and the potential consequences should an incident occur.

Conservative (protective of human health) estimates of the frequencies for an offshore LNG incident are described in Table 4.2-1 and in Section 4.2.3, with a conservative estimate of the frequencies for incidents involving offshore or onshore pipelines described in Table 4.2.4-5. These frequencies were developed to provide a measure for comparing the potential impacts from the proposed Project with the potential "involuntary" risks associated with other types of incidents, which are shown in Table 4.2.7-1. These risks are described as being involuntary, because—unlike risks associated with an activity that someone chooses to engage in (for example, recreational activities like mountain biking or sky-diving)—members of the public are exposed to involuntary risks simply as a result of where they might live, work, or recreate.

Definitions for significant adverse effects on public safety—consequences deemed to represent a significant impact—were developed based on scoping comments, analyses from previous environmental assessments conducted in California and through consultation with the lead Agencies. Any impact on public safety from LNG operations, the odorization facility, or the offshore or onshore natural gas pipelines would be considered significant and require additional mitigation if the Project construction or operation resulted in the following adverse effects:

- Loss of life or serious injury to people other than those involved with the Project (e.g., other than FSRU, tanker, or tug crews, or operations or maintenance personnel working at onshore facilities); or

- Long-term damage to the environment.

The determination of an impact's significance is described in Sections 4.1.3 and 4.1.4, and includes assigning an impact class (Classes I through IV) based on the potential adverse effect and the potential duration of the adverse effect (e.g., the adverse effect is temporary, short term, long-term, or permanent). For public safety impacts, the determination of an appropriate class for each impact was based solely on the potential for causing serious injury or fatality to a member of the public, which resulted in primarily Class I designations for these types of incidents. Class I impacts are defined as those for which a significant adverse effect remains even after mitigation. The highest priority would be to prevent accidents, and then to ensure appropriate response should an accident occur. Most of the Class I impacts are accidents or other unanticipated releases. This does not necessarily mean that such impacts would occur. On the contrary, most have a very low probability of occurring; however, if they were to occur, the consequences would be significant according to the conservative criteria the Project EIS/EIR team identified.

However, a number of mitigation measures would be implemented to substantially reduce the frequency of an incident occurring (e.g., upgrading all pipelines to Class 3 design criteria, and implementation of rigorous inspection and testing for pipelines in HCAs), and to reduce the potential consequences should an incident occur (e.g., installation of automatic valves to isolate pipeline sections in HCAs would limit the potential duration of a release or fire from a pipeline rupture without any further action by emergency services, or reducing the pipeline operating pressure would decrease the potential area that might be impacted by an ignited gas release).

Table 4.2.7-1. Comparison of Transportation Risks[a]

Type	5-Year Average	General Population Risk Per Year	Risk Based on Exposure or Other Measures
Motor Vehicle	41,616	1 in 6,300	1.7 deaths per 100 million vehicle miles
Large Trucks[b]	5,195	1 in 51,000	2.8 deaths per 100 million vehicle miles
Motorcycles	2,222	1 in 119,000	22 deaths per 100 million vehicle miles
Railway	1,096	1 in 242,000	1.6 deaths per million train miles
Bicycles	795	1 in 333,000	---
Commercial Air Carriers[d]	169	1 in 1,568,000	0.7 deaths per 100 million aircraft miles; 0.19 deaths per million aircraft departures
Proposed Project – Offshore and Onshore Pipelines	---	~1 in 100,000 (per pipeline mile)	---
Proposed Project – Offshore LNG Incident	---	~1 in 1,000,000 to 1 in 10,000,000	---

[a] A Comparison of Risk, U.S. DOT, http://hazmat.dot.gov/riskcompare.htm
[b] Large trucks are defined as having a gross vehicle weight greater than 10,000 pounds.
[c] Includes large and commuter airlines.

Table 4.2.8-1 Summary of Public Safety Impacts and Mitigation Measures

Impact	Mitigation Measure(s)
PS-1: An operational incident due to human error, upsets, or equipment failures, or as a result of natural phenomena (tsunami, high winds, etc.) could cause a release of LNG from process or loading equipment (Class II).	**AMM PS-1a**. **Applicant Engineering and Project Execution Process.** The Applicant would undertake eight specific commitment items: front end engineering design, offshore site survey, Safety Cases (HAZOPs, risk analyses), detailed design, basin model tests, third-party verification, quality and safety audits, pre-startup reviews. **AMM PS-1b. Obtain Class Certification and a Safety Management Certificate for the FSRU.** Class certification and a safety management certificate, although not required under international agreements (i.e., through the IMO) for the FSRU, would be voluntarily obtained by the Applicant. **AMM PS-1c. Periodic Inspections and Surveys by Classification Societies.** The Applicant would have periodic inspections of the FSRU conducted by classification societies, including annual inspections and a full survey after five years of facility operation and every five years thereafter. **AMM PS-1d. Designated Safety/ Exclusion Zone and Area to be Avoided.** The Applicant would monitor a 1,640-foot (500 m) radius safety zone to be designated by the USCG around the FSRU, where public maritime traffic would be excluded, and a 2 NM (2.3 miles or 3.7 km) Area to be Avoided. **AMM MT-6a. Patrol Safety Zone and Monitor Traffic.** The tug/supply vessel on standby duty would patrol the DWP's designated safety zone, except during docking and undocking operations. **MM PS-1e. Include LNG cargo tank fire survivability after loss of insulation in engineering design analyses.** Safety engineering, HAZIDs, HAZOPs, and QRA supporting the detailed engineering design shall include cases where cargo tank insulation is presumed to fail in the event of a fire. **MM PS-1f. Include structural component exposure to temperature extremes in engineering design analyses.** Safety engineering, HAZIDs, HAZOPs, and QRA supporting the detailed engineering design shall include cases where decking, hulls, and structural members are exposed to both cryogenic temperatures from spilled LNG and exposure to extreme heat from a fire. **MM PS-1g. Conduct Post-Operational HAZOPs.** HAZOPs shall be conducted that address all LNG operations before beginning operation and after one year of operation, and every two years thereafter. **MM PS-1h. Use Standby Tug/Supply Vessel**

Table 4.2.8-1 Summary of Public Safety Impacts and Mitigation Measures

Impact	Mitigation Measure(s)
	and Vessel Thrusters to Maintain FSRU or Carrier on Station. Emergency operations procedures shall incorporate the use of the tug and thrusters to maintain the FSRU position in the event of a failure of the mooring system or to maintain the LNG carrier position in the event of a loss of propulsion or control.
PS-2: A high-energy collision with the FSRU or an LNG carrier and another vessel or an intentional attack could cause a rupture of the Moss tanks holding LNG, leading to a release of an unignited flammable vapor cloud that could extend beyond the 1,640-foot (500 m) radius safety zone around the FSRU, or could impact members of the boating public in the vicinity of an LNG carrier (Class I).	**AMM PS-2a. Equip FSRU and LNG Carriers with AIS, Radar, and Marine VHF Radiotelephone.** The Applicant would equip the LNG carriers and the FSRU with an AIS and with real-time radar and marine VHF radiotelephone capabilities. **AMM PS-1a**. **Applicant Engineering and Project Execution Process.** The Applicant would undertake eight specific commitment items. **AMM PS-1b. Obtain Class Certification and a Safety Management Certificate for the FSRU.** Although class certification and a safety management certificate are not required under international agreements (i.e., through the IMO) these would be voluntarily obtained by the Applicant. **AMM PS-1c. Periodic Inspections and Surveys by Classification Societies.** The Applicant would have periodic inspections of the FSRU conducted by classification societies, including annual inspections and a full survey after five years of facility operation and every five years thereafter. **AMM PS-1d. Designated Safety/ Exclusion Zone and Area to be Avoided.** The Applicant would monitor a 1,640 foot (500 m) radius safety zone to be designated by the USCG around the FSRU, where public maritime traffic would be excluded, and a 2 NM (2.3 miles or 3.7 km) Area to be Avoided. **AMM MT-6a. Patrol Safety Zone.** The tug/supply vessel on standby duty would patrol the DWP's designated safety zone, except during docking and undocking operations. **MM PS-2b. Homeland Security/USCG/Port Authority terrorist interdiction actions.** These potential actions are not discussed specifically in this report. However, actions to prevent the takeover of a vessel by crew members or third parties shall be implemented to prevent an intentional high-speed collision with a large vessel. **MM PS-2c. Active Response to Approaching Vessels or Aircraft.** At a predetermined distance (described in shipboard plans), consideration shall be given to using the standby tug to intercept approaching vessels, and action shall be taken

Table 4.2.8-1 Summary of Public Safety Impacts and Mitigation Measures

Impact	Mitigation Measure(s)
	using the FSRU thrusters or the tug to rotate the FSRU to reduce the potential for impact with the approaching vessel. Guidance for these communications, decision criteria for taking action, and avoidance actions shall be included in the facility operations and security manuals. **MM PS-2d. Provide Aids to Aircraft Navigation.** The Applicant shall ensure that all required information is provided to the Federal Aviation Administration (FAA) as necessary, to place the FSRU location, safety zone information, and subsea pipeline locations and warnings on aviation sectional maps. This shall include a Notice to Mariners for chart correction, and inclusion on the next edition of applicable navigation charts (and aviation sectional charts). These data shall be provided sufficiently early to allow incorporation of these changes and issuance of charts prior to commencing construction activities. Securite broadcasts on VHF-FM shall be made prior to an LNG carrier mooring or unmooring. This action shall be included in the facility and carrier operations plans. **MM PS-1e. Include LNG cargo tank fire survivability.** Safety engineering, HAZIDs, HAZOPs, and QRA supporting the detailed engineering design shall include cases where cargo tank insulation is presumed to fail in the event of a fire. **MM PS-1f. Include structural component exposure to temperature extremes in engineering design analyses.** Safety engineering, HAZIDs, HAZOPs, and QRA supporting the detailed engineering design shall include cases where decking, hulls, and structural members are exposed to both cryogenic temperatures from spilled LNG and exposure to extreme heat from a fire. **MM PS-1g. Conduct Post-Operational. HAZOPs.** HAZOPs shall be conducted that address all LNG operations before beginning operation and after one year of operation and every two years thereafter. **MM PS-1h. Use Standby Tug/Supply Vessel and Vessel Thrusters.** Emergency operations procedures shall incorporate the use of the tug and thrusters to maintain the FSRU position in the event of a failure of the mooring system, or to maintain the LNG carrier position in the event of a loss of propulsion or control. **MM MT-6b. Radar to Detect Approaching Vessels.** Live radar and visual watch shall be used to detect and identify approaching vessels and note

Table 4.2.8-1 Summary of Public Safety Impacts and Mitigation Measures

Impact	Mitigation Measure(s)
	approaching aircraft at all times. **MM MT-6d. Lights and Sound Signals.** The FSRU shall be equipped with sound signals and lit in a fashion to uniquely differentiate it from vessels under way. **MM MT 6e. Information for Navigational Charts.** The Applicant shall ensure that all required information is provided to the USCG and other agencies, as necessary, to place the FSRU location, safety zone information, and subsea pipeline locations and warnings on navigational charts. **MM MT 6f. Securite Broadcasts.** Securite broadcasts on VHF-FM shall be made prior to an LNG carrier mooring or unmooring.
PS-3: There is a potential for fishing gear to become hung up on the pipeline and potentially damage one or both of the subsea pipelines. Similar damage may occur due to a seismic event or subsea landslide (Class I).	**AMM PS-3a. Concrete-Coatings Expected to add Mass and Stability in Shallower Waters.** The Applicant would ensure that pipelines laid on the seafloor in shallower waters would be concrete-coated, which would provide additional pipeline mass and increase the likelihood that the fishing gear would detach from the vessel before it damages the pipeline. **AMM PS-3b. Seismic Area Imposes more Stringent Design Requirements.** The offshore pipelines for this Project would be designed and constructed to ensure that pipeline integrity is maintained during severe seismic events that might be expected to bend or bow the pipelines in the same way as trawling gear might. The Applicant would design and install pipelines to meet seismic criteria in this area. **AMM PS-3c. Comply with Design, Maintenance, inspection, and testing requirements.** The Applicant has committed to design, install, operate, maintain, and inspect pipelines to meet regulatory requirements, which includes automatic monitoring of pipeline pressure and other conditions using a supervisory control and data acquisition (SCADA) system and routine internal pipeline inspections (including smart pigs). This reduces the chances for potential deterioration or incidental damage to the pipeline to go undetected and unrepaired. **MM PS-3d. Areas Subject to Accelerated Corrosion Cathodic Protection System.** The Applicant shall identify any offshore areas where the pipeline may be subject to accelerated corrosion due to proximity to utility cables or adjacent pipeline cathodic protection systems. Cathodic protection systems shall be installed and made fully operational as soon as possible during

Table 4.2.8-1 Summary of Public Safety Impacts and Mitigation Measures

Impact	Mitigation Measure(s)
	pipeline construction. **MM PS-3e. Emergency Communication/ Warnings.** The Applicant's emergency plans and procedures shall require immediate notification of vessels in any offshore area, including hailing and Securite broadcasts, and immediate notification of local police and fire services whenever the monitoring system indicates that there might be a problem with subsea pipeline integrity. **MM MT-6d. Lights and Sound Signals.** The FSRU Shall be equipped with sound signals and lit in a fashion to uniquely differentiate it from vessels under way. **MM MT 6e. Information for Navigational Charts.** The Applicant shall ensure that all required information is provided to the USCG and other agencies, as necessary, to place the FSRU location, safety zone information, and subsea pipeline locations and warnings on navigational charts. **MM MT 6f. Securite Broadcasts.** Securite broadcasts on VHF-FM shall be made prior to an LNG carrier mooring or unmooring.
PS-4: The potential exists for accidental or intentional damage to the buried or aboveground pipelines or valves carrying unodorized natural gas. Similar damage may occur due to a seismic event. This would result in the release of an unodorized natural gas cloud at concentrations that are likely to be in the flammable range (Class I).	**AMM PS-4a. Pipeline and Facility Monitoring and Inspections.** The Applicant has committed to design, install, operate, maintain, and inspect pipelines and other Project facilities to meet regulatory requirements. **MM PS-4b. Define Shore Crossing as Pipeline HCA.** Any onshore area above the mean low tide mark where the pipeline is carrying unodorized natural gas shall be defined as an HCA. **MM PS-4c. Automatic Monitoring for Flammable Gas.** An automatic monitoring system (sniffer) shall be designed and installed in shore crossing HCAs where the pipeline is carrying unodorized natural gas. **MM PS-4d. Emergency Communication and Warnings.** The Applicant's emergency plans and procedures shall require immediate notification of vessels in any nearshore area, immediate notification of local police and fire services, and visual and audible alarms to alert members of the public in the area.
PS-5: The potential exists for accidental or intentional damage to the odorant tank storage or injection components that would release highly flammable and foul-smelling odorant as a liquid (Class II).	**AMM PS-5a. Construction, Maintenance, and Operation in accordance with regulatory requirements.** SoCalGas would design, construct, maintain, and operate proposed Project facilities in accordance with applicable codes, standards, and regulatory requirements. **AMM HAZ 2a. Manage Used Oil in Accordance**

Table 4.2.8-1 Summary of Public Safety Impacts and Mitigation Measures

Impact	Mitigation Measure(s)
	with USEPA and State Requirements. The Applicant would return used oil to shore in the same labeled and DOT-approved containers used to provide the replacement oil, which would ensure that appropriate containers would be used for all oil in storage and in transport. **AMM HAZ-5a. Spill Prevention, Countermeasures, and Control Plan.** An SPCC Plan would be prepared and approved prior to initiation of HDD operations. Before drilling begins, site workers would be trained to recognize and respond to spills in accordance with the SPCC Plan and to notify regulatory authorities. **MM PS-5b. Provide Automatic Gas Detection and Fire Suppression Systems at the Storage Tank Location.** Automatic monitoring for flammable gas shall be installed in the tank area to provide early warning of any leaks. **MM PS-5c. Evaluate adding odorant to the LNG prior to shipping; Implement when feasible.** Industry efforts to identify an economical and technically feasible odorant that could be added to LNG are currently ongoing.
PS-6: An operational incident due to human error or equipment failures, or as a result of natural phenomena (earthquakes, landslides, etc.) could cause a release of natural gas from the high pressure natural gas pipelines. The greatest hazard to public safety from natural gas pipelines is from a component or pipeline failure that releases natural gas that is subsequently ignited (Class I).	**AMM PS-6a. Applicant would construct all pipelines to meet Class 3 Design Criteria.** The Applicant would construct all pipeline segments to meet the minimum design criteria for a Class 3 location, which will provide an increased level of protection in areas where requirements would be less stringent based on current population density along the pipeline (i.e., in Class 1 or Class 2 locations). **AMM PS-3c. Comply with Design, Maintenance, Inspection, and Testing Requirements.** The Applicant has committed to design, install, operate, maintain, and inspect pipelines to meet regulatory requirements, which includes automatic monitoring of pipeline pressure and other conditions using a supervisory control and data acquisition (SCADA) system and routine internal pipeline inspections (including smart pigs). This reduces the chances for potential deterioration or incidental damage to the pipeline to go undetected and unrepaired. **MM PS-6b. Pipeline Integrity Management Program.** The Applicant shall develop and implement a pipeline integrity management program, including confirming all potential HCAs (including identification of potential sites from “licensed” facility information [day care, nursing care, or similar facilities] available at the city and county level) and ensuring that the public education

Table 4.2.8-1 Summary of Public Safety Impacts and Mitigation Measures

Impact	Mitigation Measure(s)
	program is fully implemented prior to commencing pipeline operations. **MM PS-6c. Include Automatic Shut Down Valves.** The Applicant shall include automatic shutdown valves (ASDVs) with appropriate blow-down time on the upstream side of the pipeline and check valves on the downstream side in HCAs. This provides additional means for isolating segments of the pipeline should a rupture occur. **MM PS-3d. Areas Subject to Accelerated Corrosion, Cathodic Protection System.** The Applicant shall identify any offshore areas where the pipeline may be subject to accelerated corrosion due to proximity to utility cables or adjacent pipeline cathodic protection systems. Cathodic protection systems shall be installed and made fully operational as soon as possible during pipeline construction.
PS-7: In the event of an accident, there is a greater likelihood of injury, fatality, and property damage due to fire and explosion in Areas with Less Robust Housing Construction. (Class I)	**AMM PS-6a. Applicant Would Construct all Pipelines to Meet Class 3 Design Criteria.** The Applicant would construct all pipeline segments to meet the minimum design criteria for a Class 3 location, which will provide an increased level of protection in areas where requirements would be less stringent based on current population density along the pipeline (i.e., in Class 1 or Class 2 locations). **MM PS-7a. Define HCA for any PIR circle that includes one or more mobile homes. Assist residents to improve emergency planning.** Areas where the PIR includes one or more normally occupied mobile homes or travel trailers used as temporary or semi-permanent housing shall be defined as an HCA. Mitigation measures (e.g., smoke detectors and outreach for notification and escape planning) shall be provided to all residents of that housing. **MM PS-7b. Define an HCA for areas where the PIR includes part or all of a manufactured-home residential community.** Provide mitigation measures (e.g., smoke detectors and outreach for notification and escape planning) to all residents of that community. **MM PS-7c. Implement Public Education/ Awareness Program.** In accordance with pipeline safety requirements contained in 49 CFR 192 Part O, the Applicant shall develop and implement a public education and awareness program that complies with American Petroleum Institute's (API) recommended practice (RP) 1162, "Public Awareness Programs for Pipeline Operators," including providing specific information to residents

Table 4.2.8-1 Summary of Public Safety Impacts and Mitigation Measures

Impact	Mitigation Measure(s)
	regarding ways to reduce their risks in the event of a fire or other release involving the pipeline, and recommended ways to test and maintain household smoke detectors.
PS-8: In the event of an accident, there is an increased potential for injury or fatality near Center Road Pipeline Milepost 4.1 due to Community Activities Outdoors. (Class I)	**AMM PS-6a. Applicant Would Construct all Pipelines to Meet Class 3 Design Criteria.** The Applicant would construct all pipeline segments to meet the minimum design criteria for a Class 3 location, which will provide an increased level of protection in areas where requirements would be less stringent based on current population density along the pipeline (i.e., in Class 1 or Class 2 locations). **MM PS-8a. Define HCA.** An HCA shall be defined in this area using the mobile home park property boundaries and any garden areas as the edge of an outdoor area that meets HCA criteria.

4.2.8 Impact Analysis and Mitigation

Mitigation measures that are specified in the EIS/EIR, as modified and approved by the responsible agencies, would be incorporated as conditions of any license or lease granted to the Applicant. In the same way that the lead agencies would evaluate the design, construction, and operations of the proposed Project with the assistance of a third-party verification agent (see Subsection 4.2.6.2), the USCG, with the assistance of a third-party verification agent and in consultation with the CSLC would monitor installation of the FSRU and pipelines pursuant to the Mitigation Monitoring Program (MMP) for this proposed Project (see Section 6 of this EIS/EIR).

A summary of impacts and mitigation measures is provided in Table 4.2.8-1. A discussion of the differences between Applicant-proposed mitigation measures (AMM) and agency-recommended mitigation measures (MM) is provided in Section 4.1, "Introduction to Environmental Analysis."

4.2.8.1 Impacts and Mitigation – LNG Incidents

Impact PS-1. Potential Release of LNG due to Operational Incident or Natural Phenomena

An operational incident due to human error, upsets, or equipment failures or as a result of natural phenomena (tsunami, high winds, etc.) could cause a release of LNG from process or loading equipment (Class II).

Operational accidents of varying levels of severity occur at all types of processing facilities and at facilities where materials are transferred from one container to another. The stringent design requirements that would be imposed on the FSRU and on any newly constructed LNG carriers are intended to provide inherent engineered safety features for these vessels and equipment that reflect the type and magnitude of site-specific seismic, sea, and weather conditions to which the FSRU, its moorings, and pipeline connections might be subjected. In addition, USCG regulations and international and class certification requirements mandate that the Applicant would develop detailed plans to address all aspects of facility operation, security, and emergency preparedness and response; these plans would be reviewed by relevant agencies who would also conduct compliance inspections. Many of these requirements are summarized in Subsection 4.2.6.2, "Applicable Safety Standards." These requirements are also discussed in more detail in the Marine Safety and Security (MS&S) section of Appendix C to this EIS/EIR. For example, a detailed discussion of the minimum requirements for emergency planning and emergency exercises and drills is discussed as part of the mitigation measures contained in Section 2.1 of the MS&S section contained in Appendix C.

Agencies that will be responsible for detailed review and inspection of the proposed Project design, construction, and operation are identified in Table 4.2.6-1. There would be significant Federal, State, and local agency involvement in all phases of the proposed Project design, construction, and operation.

Computer modeling of credible LNG releases that might be encountered during an operational incident indicated that the potential impacts would not extend beyond the 1,640-foot (500 m) safety zone, and hence would pose no potential threat to public safety.

The USCG responds to emergencies offshore. Should an incident involving the FSRU occur, the relatively large distance from shore would be expected to allow sufficient time for notification and mobilization of emergency response resources (e.g., additional tug support, fireboats, rescue for facility or carrier personnel) to increase crew safety and to ensure that public safety is not impacted. The proposed Project would not require additional funding, training, equipment, or staffing resources for or from local city or county emergency services.

The Applicant has incorporated the following measures to reduce the potential of incidents due to operational errors, upsets, or equipment failures or natural phenomena:

AMM PS-1a. **Applicant Engineering and Project Execution Process.** The Applicant would undertake—regardless of any less stringent regulatory requirements—the following steps to design, build, and operate the proposed Project:

1) Prior to final internal project funding, undertake a full Front End Engineering Design (FEED) exercise with a suitably qualified and experienced contractor under the management of an Applicant technical team. This would define the engineering requirements for the complete Project and identify sources for all remaining detailed information and data, to be ready for internal Project sanction and final detailed engineering.

2) Undertake a comprehensive offshore site survey to determine bathymetry, geology, and geotechnical characteristics of the area in and immediately around the locations of each element of the Project. This would require mobilization of specialized marine vessels and crews to perform the acoustic surveying and soil coring for the shallow water horizontal directional drilling (HDD) of the pipelines crossing under the beach to the FSRU mooring in deep water. This information would provide additional information for the final detailed design of the HDD, the pipelines, cable crossings, pipeline end manifolds, and the mooring system anchors.

3) Fully implement the proposed Project under a self-imposed "Safety Case" regime for the detailed design of the proposed Project. This would begin with the FEED but could be completed only when the level of the facility definition is in the advanced detailed design phase. This would require a complex series of additional detailed safety checks and balances be put into place, including HAZID, hazard and operability studies (HAZOPs), quantitative risk analyses (QRA), formal safety analyses (FSA), and associated safety engineering exercises such as process plant modeling and analyses. This would be finalized during the detailed design of the FSRU safety systems, the process plant and deck layouts, and the associated systems such as piping and utilities and the control systems and procedures. Upon startup, the safety case would become a "living" tool for the facility operating team—one that would be updated and reanalyzed as needed based on operational experience—to ensure that the proposed Project meets or exceeds required standards during all phases of operation.

4) Upon internal Project sanction/funding, ensure detailed engineering would be conducted for all components by suitably qualified and experienced contractors under the management of an Applicant technical team and in accordance with demanding technical requirements that would be carefully defined in contractual documents. The selected qualified engineering contractors would likely be different for the hull, the regasification topsides, the mooring, pipelines, etc. Using this process, the Applicant would ensure that all engineering is executed to meet or exceed the regulatory and Applicant's internal requirements.

5) Commission a series of model tests of the FSRU facility at an experienced and well-established model test basin. More advanced detailed theoretical analyses would be completed first to identify the governing criteria and cased to be modeled in the basin. These model tests would cover both the survival sea

states without an LNG carrier moored alongside and the operational sea states with the carrier moored alongside the FSRU. FSRU motions and mooring system loads would be measured under survival storm conditions to confirm the calculated results. Similarly, relative and absolute motions of and between the FSRU and the berthed carrier would be measured to confirm the operability limits of the berth mooring, fender, and loading arm systems. This would also provide information about FSRU motions for the detailed design of the topsides equipment.

6) The Applicant would require independent third-party verification of detailed engineering, procured equipment, fabrication, construction, and offshore installation and commissioning of all Project components. Where such independent third-party verification would be required by a regulatory agency, or in order to obtain class certification, a single verification process would be conducted to ensure efficiency of this verification.

7) During the construction phases of the proposed Project, both quality and safety audits at major fabrication/construction sites would be undertaken by the Applicant to ensure quality and safety of the Project components. Actual safety and quality performance during construction would be a contractual obligation for the various contractors selected by the Applicant.

8) Before releasing the FSRU from its inshore commissioning (before towing to the proposed Project site) and after offshore installation of all components, but before facility startup, the Applicant would conduct a formal pre-startup review. The status of the facility, quality assurance, “outstanding items,” operational preparedness, and compliance with legal and regulatory commitments would be carefully reviewed in a team session with final checks before proceeding first with the tow and second with initial startup of LNG operations. A number of action items would generally be identified in such sessions; some would require closure before proceeding to the next step, and others would be identified for action by specific deadlines or milestones. This process and any findings would be formally documented.

AMM PS-1b. **Obtain Class Certification and a Safety Management Certificate for the FSRU.** Class certification and a safety management certificate are required under international agreements (i.e., through the IMO) for vessels engaged in international voyages. Although this would not be required for the stationary FSRU, the Applicant would obtain class certification for the facility. The Applicant would voluntarily provide a documented management system that would be in compliance with the ISM Code and the Applicant’s internal health, safety, engineering, and construction standards. When operational, the FSRU would be certified under ISM, International Organization for Standardization (ISO) ISO-9000 quality standards and ISO-14000 environmental standards.

AMM PS-1c. **Periodic Inspections and Surveys by Classification Societies.** The Applicant would have conducted periodic inspections of the FSRU by classification societies, including annual inspections and a full survey after five years of facility operation and every five years thereafter. This would help ensure that shipboard procedures are regularly reviewed and updated and that processing and emergency equipment would be maintained appropriately and repaired or upgraded as necessary.

AMM PS-1d. **Designated Safety (exclusion) Zone and Area to be Avoided.** The Applicant would monitor a 1,640-foot (500 m) radius safety zone to be designated by the USCG around the FSRU, where public maritime traffic would be excluded. The Applicant has also proposed designating an Area to be Avoided with a radius of 2 NM (2.3 miles or 3.7 km) around the FSRU. Each of these zones would be marked on nautical charts and would serve as part of the Notice to Mariners to avoid these areas.

AMM MT-6a. **Patrol Safety Zone and Monitor Traffic** also applies here (see Section 4.3, "Marine Traffic").

<u>Mitigation Measures for Impact PS-1: Operational or Natural Phenomena LNG Release Incident</u>

MM PS-1e. **Include LNG cargo tank fire survivability after loss of insulation in engineering design analyses.** Safety engineering, HAZIDs, HAZOPs, and QRA supporting the detailed engineering design shall include cases where cargo tank insulation is presumed to fail in the event of a fire.

MM PS-1f. **Include structural component exposure to temperature extremes in engineering design analyses.** Safety engineering, HAZIDs, HAZOPs, and QRA supporting the detailed engineering design shall include cases where decking, hulls, and structural members are exposed to both cryogenic temperatures from spilled LNG and exposure to extreme heat from a fire.

MM PS-1g. **Conduct Post-Operational HAZOPs.** HAZOPs shall be conducted that address all LNG operations prior to beginning operation and after one year of operation in the manner and complexity prescribed by the Risk Management Program (RMP) under Clean Air Act Section 112 (r) and further described in regulations contained in 40 CFR 68. The results of these reviews shall be used to improve and refine operations practices and emergency response procedures. After the initial and first post-operational HAZOPs, additional HAZOPs shall be conducted every two years unless there has been a change in equipment or other significant change. The results of these reviews shall be reviewed as part of configuration management when any equipment, operational, or procedural changes have been undertaken that would necessitate conducting an additional HAZOP review for the new configuration. HAZOPs may be conducted by the Applicant or by a qualified third party, including participation by the CSLC.

MM PS-1h. **Use Standby Tug/Supply Vessel and Vessel Thrusters to Maintain FSRU or Carrier on Station.** Emergency operations procedures shall incorporate the use of the tug and thrusters to maintain the FSRU position in the event of a failure of the mooring system or to maintain the LNG carrier position in the event of a loss of propulsion or control.

Hazard and risk evaluations for these types of incidents indicated that the potential consequences would not extend beyond the 1,640-foot (500 m) safety (exclusion) zone around the FSRU. The impact would therefore be reduced to less than significant with the implementation of the measures described above.

Impact PS-2. Potential Release of LNG due to High Energy Marine Collision or Intentional Attack

A high-energy collision with the FSRU or an LNG carrier and another vessel or an intentional attack could cause a rupture of the Moss tanks holding LNG, leading to a release of an unignited flammable vapor cloud that could extend beyond the 1,640-foot (500 m) radius safety zone around the FSRU, or could impact members of the boating public in the vicinity of an LNG carrier (Class I).

Computer modeling indicated that a high-energy collision with another vessel could potentially cause a rupture of the Moss tanks holding LNG aboard the FSRU and that the consequences of this scenario could lead to fatalities and serious injuries to members of the public. The range of other release scenarios evaluated, including potential releases that might be caused by intentional sabotage or attacks, could also potentially result in releases of LNG that would cause impacts beyond the 1,640-foot (500 m) exclusion/safety zone around the FSRU.

The FSRU mooring would be located 2 NM (2.3 miles or 3.7 km) from the edge of the Southbound Coastwise Traffic Lane and 5 NM (5.8 miles or 9.3 km) from the Northbound Coastwise Traffic Lane. The presence of the FSRU and approaching/departing LNG carriers would likely require other vessels to make course and speed adjustments because large vessels typically try to avoid approach within 2 NM (2.3 miles or 3.7 km) of each other in the open ocean.

Mariners use the following resources to determine whether the risk of collision exists: radar tracking, visual examination of a vessel's aspect and lighting, and hailing a vessel. If the captain of an approaching vessel were to mistake the FSRU for a vessel rather than a stationary port, the FSRU captain could take several steps to avoid a collision.

AIS is a technology that the Applicant proposes to use on the FSRU and its associated LNG carriers. The AIS sends information to other ships. This information is then displayed on these ships' radar. This information includes the name of the vessel, its speed, and its course. Use of the AIS would reduce or eliminate the potential that other vessels would mistake the FSRU for a vessel. Since the FSRU and the LNG carriers would be equipped with an AIS, the risk of potential collisions would be reduced. In addition, the position of the FSRU, the safety zone, and the Area to Be Avoided, if approved by the USCG, would be placed on navigation charts. Thus, mariners would know the exact location of the FSRU and could take measures to avoid it.

The Applicant has incorporated the following into the Project:

AMM PS-2a. **Equip FSRU and LNG Carriers with AIS, Radar, and Marine VHF Radiotelephone.** The Applicant would equip the LNG carriers and the FSRU with an AIS and with real-time radar and marine VHF radiotelephone capabilities.

The following also apply here:

AMM PS-1a. **Applicant Engineering and Project Execution Process.**

AMM PS-1b. **Obtain Class Certification and a Safety Management Certificate for the FSRU**.

AMM PS-1c. **Periodic Inspections and Surveys by Classification Societies.**

AMM PS-1d. **Designated Safety (exclusion) Zone and Area to be Avoided.**

AMM MT-6a. **Patrol Safety Zone and Monitor Traffic** (see Section 4.3, "Marine Traffic").

<u>Mitigation Measures for Impact PS-2: High Energy Vessel Collision or Intentional Attack with LNG Release with or without Ignition</u>

MM PS-2b. **Homeland Security/USCG/Port Authority terrorist interdiction actions.** These potential actions will not be discussed specifically in this report. However, actions to prevent the takeover of a vessel by crew members or third parties shall be implemented to prevent an intentional high-speed collision with a large vessel.

MM PS-2c. **Active Response to Approaching Vessels or Aircraft.** At a predetermined distance (described in shipboard plans), consideration shall be given to using the standby tug to intercept approaching vessels, and action shall be taken using the FSRU thrusters or the tug to rotate the FSRU to reduce the potential for impact with the approaching vessel. Guidance for these communications, decision criteria for taking action, and avoidance actions shall be included in the facility operations and security manuals.

MM PS-2d. **Provide Aids to Aircraft Navigation.** The Applicant shall ensure that all required information is provided to the FAA as necessary, to place the FSRU location, safety zone information, and subsea pipeline locations and warnings on aviation sectional maps. This shall include a Notice to Mariners for chart correction and inclusion on the next edition of applicable navigation charts (and aviation sectional charts). These data shall be provided sufficiently early to allow incorporation of these changes and issuance of charts before beginning construction activities. Securite broadcasts on VHF-FM shall be made before an LNG carrier mooring or unmooring. This action shall be included in the facility and carrier operations plans.

The following also apply here:

MM PS-1e. **Include LNG cargo tank fire survivability after loss of insulation in engineering design analyses.**

MM PS-1f. **Include structural component exposure to temperature extremes in engineering design analyses.**

MM PS-1g. **Conduct Post-Operational HAZOPs.**

MM PS-1h. **Use Standby Tug/Supply Vessel and Vessel Thrusters to Maintain FSRU or Carrier on Station.**

MM MT-6b. **Radar to Detect Approaching Vessels** (see Section 4.3, “Marine Traffic”).

MM MT-6d. **Lights and Sound Signals** (see Section 4.3, “Marine Traffic”).

MM MT 6e. **Information for Navigational Charts** (see Section 4.3, “Marine Traffic”).

MM MT 6f. **Securite Broadcasts** (see Section 4.3, “Marine Traffic”).

The likelihood of potential impacts would be reduced from the estimated annual frequencies of about 6.1×10^{-7} per year (about six in ten million) for Worst-Case Release #1 and about 1.1×10^{-6} per year (about one in a million) for Worst-Case Release #2 with the implementation of the measures described above. Hazard and risk evaluations for these types of incidents indicated that the potential consequences would extend beyond the 1,640-foot (500 m) safety (exclusion) zone around the FSRU. The impacts would therefore still be potentially significant (i.e., could cause serious injury or fatality to members of the public) should an incident occur, e.g., as a result of an intentional attack. This impact remains significant after mitigation.

4.2.8.2 Impacts and Mitigation – Offshore Pipelines

Impact PS-3. Potential Release of Unodorized Natural Gas due to Accidental Damage of Subsea Pipelines.

There is a potential for fishing gear to become hung up on the pipeline and potentially damage one or both of the subsea pipelines. Similar damage may occur due to a seismic event or subsea landslide[1] (Class I).

As described in Section 2, "Project Description," the twin 24-inch (0.6 m) diameter subsea pipelines carrying unodorized natural gas will be buried using HDD from the onshore connection seaward approximately 0.6 miles (0.9 km) to water depths of 42.6 feet (13 m). In waters deeper than this, the offshore pipelines would be laid on the sea floor. Subsea sections laid directly on the sea floor will be concrete-coated to provide additional stability in the areas where depths are still relatively shallow.

Previous incidents of subsea natural gas pipeline ruptures due to third-party damage (dragging an anchor) have been concentrated in the Gulf of Mexico, where many older pipelines are not buried or concrete-coated and where water depths are shallow for a considerable distance from shore. In several of those cases, however, it was apparent that in shallow waters (less than 10 to 20 feet [3 to 6 m]) the released natural gas could and did form a flammable cloud once it breached the ocean surface. In the case of the proposed Project, although it is likely that mariners in the area would notice bubbling or frothing at the ocean surface, the unodorized gas would be otherwise undetectable by people, marine life, or birds in the area.

The Applicant has proposed the following mitigation measures to reduce the potential for incidents due to piping or valve failures caused by third-party damage, material defects or operational fatigue, or natural phenomena:

AMM PS-3a. **Concrete-Coatings Expected to add Mass and Stability in Shallower Waters.** The Applicant would ensure that pipelines laid on the seafloor in shallower waters would be concrete-coated, which would provide additional pipeline mass and increase the likelihood that the fishing gear would detach from the vessel before it damages the pipeline.

AMM PS-3b. **Seismic Area Imposes more Stringent Design Requirements.** The offshore pipelines for this Project would be designed and constructed to ensure that pipeline integrity is maintained during

[1] The potential for commercial fishing activities such as trawling in the area near the pipelines is discussed in Subsection 4.16, "Socioeconomics."

severe seismic events that might be expected to bend or bow the pipelines in the same way as trawling gear might. The Applicant would design and install pipelines to meet seismic criteria in this area.

AMM PS-3c. **Comply with Design, Maintenance, inspection, and testing requirements.** The Applicant has committed to design, install, operate, maintain, and inspect pipelines to meet regulatory requirements, which includes automatic monitoring of pipeline pressure and other conditions using a SCADA system and routine internal pipeline inspections (including smart pigs). This reduces the chances for potential deterioration or incidental damage to the pipeline to go undetected and unrepaired.

<u>Mitigation Measures for Impact PS-3: Release of Unodorized Natural Gas from Damaged Subsea Pipelines.</u>

MM PS-3d. **Areas Subject to Accelerated Corrosion Cathodic Protection System.** The Applicant shall identify any offshore areas where the pipeline may be subject to accelerated corrosion due to proximity to utility cables or adjacent pipeline cathodic protection systems. Cathodic protection systems shall be installed and made fully operational as soon as possible during pipeline construction.

MM PS-3e. **Emergency Communication/Warnings.** The Applicant's emergency plans and procedures shall require immediate notification of vessels in any offshore area, including hailing and Securite broadcasts, and immediate notification of local police and fire services whenever the monitoring system indicates that there might be a problem with subsea pipeline integrity.

The following also apply here:

MM MT-6d. **Lights and Sound Signals** (see Section 4.3, "Marine Traffic").

MM MT 6e. **Information for Navigational Charts** (see Section 4.3, "Marine Traffic").

MM MT 6f. **Securite Broadcasts** (see Section 4.3, "Marine Traffic").

The (unmitigated) annual frequencies of significant events per pipeline mile have been very conservatively estimated for both onshore and offshore pipelines at about 4×10^{-5} per year (four in one hundred thousand) that a pipeline incident would result in a serious public injury, and about 1×10^{-5} per year (one in one hundred thousand) that a pipeline incident would result in a public fatality. These frequencies would be expected to be reduced for the proposed Project pipelines—and in some cases significantly decreased—with the implementation of the measures described above. The impacts, however, would still be potentially significant (i.e., could cause serious injury or fatality to members of the public) should an incident occur, e.g., as a result of an intentional attack. Therefore, this impact remains significant after mitigation.

4.2.8.3 Impacts and Mitigation – Shore Crossing and Odorization Facility

Impact PS-4. Potential Release of Unodorized Natural Gas due to Accidental Damage of Pipelines

The potential exists for accidental or intentional damage to the buried or aboveground pipelines or valves carrying unodorized natural gas. Similar damage may occur due to a seismic event. This would result in the release of an unodorized natural gas cloud at concentrations that are likely to be in the flammable range (Class I).

The Applicant has proposed the following mitigation measures to reduce the potential of incidents due to piping or valve failures caused by third-party damage, material defects or operational fatigue, or natural phenomena.

AMM PS-4a. **Pipeline and Facility Monitoring and Inspections.** The Applicant has committed to design, install, operate, maintain, and inspect pipelines and other Project facilities to meet regulatory requirements, which for pipelines includes automatic monitoring of pipeline pressure and other conditions using a SCADA system and to routine internal pipeline inspections (including smart pigs). This reduces the chances for potential deterioration or incidental damage to the pipeline to go undetected and unrepaired. For the odorization facility, this requires meeting fire and building code requirements for storage of highly flammable liquids and meeting or exceeding the requirements for spill control and response under Clean Water Act regulations.

<u>Mitigation Measures for Impact PS-4: Release of Unodorized Natural Gas from Damaged Shore Crossing Pipelines.</u>

MM PS-4b. **Define Shore Crossing as Pipeline HCA.** Any onshore area above the mean low tide mark where the pipeline is carrying unodorized natural gas shall be defined as an HCA.

MM PS-4c. **Automatic Monitoring for Flammable Gas.** An automatic monitoring system (sniffer) shall be designed and installed in shore crossing HCAs where the pipeline is carrying unodorized natural gas.

MM PS-4d. **Emergency Communication and Warnings.** The Applicant's emergency plans and procedures shall require immediate notification of vessels in any nearshore area, immediate notification of local police and fire services, and visual and audible alarms to alert members of the public in the area (e.g., warning horns and strobe lights located along the onshore pipeline HCA corridor whenever the monitoring system indicates that there might be a problem with the pipeline integrity in that area.

The (unmitigated) annual frequencies of significant events per pipeline mile have been very conservatively estimated for both onshore and offshore pipelines at about 4×10^{-5} per year (four in one hundred thousand) that a pipeline incident would result in a serious public injury and about 1×10^{-5} per year (one in one hundred thousand) that a pipeline incident would result in a public fatality. These frequencies would be expected to be reduced for the proposed Project pipelines—and in some cases significantly decreased—with the implementation of the measures described above. The impacts, however, would still be potentially significant (i.e., could cause serious injury or fatality to members of the public) should an incident occur, e.g., as a result of an intentional attack. Therefore, this impact remains significant after mitigation.

Impact PS-5. Potential Odorant Release and Fire

The potential exists for accidental or intentional damage to the odorant tank storage or injection components that would release highly flammable and foul-smelling odorant as a liquid (Class II).

The Applicant has proposed co-locating the odorization facility with the metering station at the shore crossing. During public scoping, commenters asked for additional information regarding relocating the odorization facility to the FSRU or adding odorant at the overseas facility where the natural gas would be liquefied before loading onto an LNG carrier vessel and shipped to the proposed Project. These alternatives have not been studied in detail as part of the EIS/EIR evaluation. A few general observations regarding the difference in impacts compared with the proposed Project are noted below:

Odorization Facility Located on the FSRU

This option would eliminate the potential for transporting unodorized natural gas in any portion of the shore crossing/onshore pipelines, which would reduce the risk that people boating in the nearshore area or who are on or near the beach would be potentially exposed to a release of natural gas that they would not be able to detect by smell. Pressurized tanks containing odorant would have to be regularly transported by boat from the shore to the FSRU, and supply vessel collisions that could result in potential releases, fires, and explosions of this highly flammable material would pose an additional hazard to the boating public compared with the proposed Project. The odorant is toxic to marine life, and potential spills during transport offshore would pose an increased environmental risk compared to the proposed project.

Odorize LNG at Overseas Liquefaction Facility

Adding an odorant to natural gas or to compressed natural gas is common industry practice. However, normal natural gas odorants freeze and separate and are not useful when added to a cryogenic liquid such as LNG. LNG stored and used in the U.S. for alternative-fueled vehicles does not currently contain an odorant, although there are ongoing initiatives to identify an economical odorant to be added to LNG, e.g., by the South Coast AQMD[2] and the Natural Gas Vehicle Industry Infrastructure Working Group[3]. It is unclear at this time if it is in fact technically and economically feasible to add odorant to LNG, but research is ongoing and would be expected to yield results during the lifetime of the proposed Project.

Odorization Facility at Shore Crossing

As described in Section 2, the Applicant has not yet finalized the design for the odorization facility. Depending on the final design, odorant would be stored in a 10,000-gallon (37.9 m^3) storage tank that would require refilling approximately two to three times per year. Alternatively, the facility could use a 5,000 to 6,000-gallon (18.9 m^3 to 22.7 m^3) storage tank that would require refilling about four times per year.

Minor releases of odorant due to human error when connecting or disconnecting transfer piping when the storage tanks are being filled would be expected to result in nuisance odor complaints from people in the vicinity. Larger spills of odorant would be contained within the containment berm around the storage tanks but would need to be cleaned up relatively quickly (e.g., using a vacuum truck designed to handle flammable liquids) to minimize the evaporation of this flammable and obnoxious-smelling material. Compliance with building, fire, mechanical and electrical codes will help ensure that the odorant storage and injection facility is structurally sound, meets seismic requirements, and meets the electrical classification requirements for the potential flammable hazard.

An accident or intentional attack on the odorant storage tank that included ignition of the spilled pool of material would require prompt response by local fire and emergency services because the pool fire would be located directly under the pressurized storage tank containing the remaining volume of odorant. This could result in potentially serious localized damage, particularly if the fire produces sufficient heat for a relatively long period of time to cause a rupture or explosion of the remainder of the storage tank shell. Like any other fire involving a flammable liquid in tank storage, emergency services may require the area near the facility be evacuated during any fire incident involving the odorant storage and injection facility.

The Applicant has proposed the following mitigation measures to reduce the potential of incidents due to operational errors, upsets, or equipment failures or natural phenomena:

AMM PS-5a. **Construction, Maintenance, and Operation in accordance with regulatory requirements.** SoCalGas would design, construct, maintain, and operate proposed Project facilities in accordance with applicable codes, standards, and regulatory requirements.

[2] South Coast AQMD Technology Committee report, Board Meeting, March 1, 2002, http://www.aqmd.gov/hb/2002/020337a.html

[3] http://www.fbodaily.com/cbd/archive/2000/07(July)/25-Jul-2000/Asol001.htm

AMM HAZ 2a. **Manage Used Oil in Accordance with USEPA and State Requirements** also applies here .(see Section 4.12, "Hazardous Materials").

AMM HAZ-5a. **Spill Prevention Countermeasure and Control Plan** also applies here .(see Section 4.12, "Hazardous Materials")..

<u>Mitigation Measures for Impact PS-5: Release and Fire of Natural Gas Odorant.</u>

MM PS-5b. **Provide Automatic Gas Detection and Fire Suppression Systems at the Storage Tank Location.** Automatic monitoring for flammable gas shall be installed in the tank area to provide early warning of any leaks. Automatic fire detection and suppression systems shall be provided to protect the tank area and to ensure that manual action is not necessary to provide tank cooling and fire suppression in the event that a fire occurs.

MM PS-5c. **Evaluate adding odorant to the LNG prior to shipping; Implement when feasible.** Industry efforts to identify an economical and technically feasible odorant that could be added to LNG are currently ongoing. Detailed engineering design for the proposed Project shall evaluate options available at that time for odorizing LNG. The Applicant shall monitor such industry efforts and shall notify the USCG and the CSLC when such odorants become available. At such time as LNG odorants become available, the Applicant shall propose facility modifications as needed to deliver and regasify odorized LNG to the FSRU, which would eliminate the need for an odorization facility at the shore crossing or on- board the FSRU and eliminate the transport of unodorized natural gas in any part of the system.

The odorization facility would be located within a fenced area in an area where there is currently no residential housing or business occupancies in close proximity. The impact would therefore be reduced to less than significant with the implementation of the measures described above.

4.2.8.4 Impacts and Mitigation– Onshore Pipelines

Impact PS-6. Potential Release of Natural Gas due to Operational Incident or Natural Phenomena

An operational incident due to human error or equipment failures, or as a result of natural phenomena (earthquakes, landslides, etc.) could cause a release of natural gas from the high pressure natural gas pipelines. The greatest hazard to public safety from natural gas pipelines is from a component or pipeline failure that releases natural gas that is subsequently ignited (Class I).

Operational accidents of varying levels of severity occur on all types of pipelines. These are discussed in more detail in Subsection 4.2.4, “Risk Evaluation – Offshore and Onshore Natural Gas Transportation.” The stringent design requirements that would be imposed on the new pipeline to be constructed as part of the proposed Project are detailed in Subsection 4.2.6, “Regulatory Setting: Applicable Safety Standards and Responsibilities, ”including recently upgraded requirements requiring the identification of HCAs and implementation of additional safety measures for those areas where consequences of a release could be greater than in less populated areas. These design, inspection, maintenance, testing, and reporting requirements are intended to provide a significantly increased level of safety compared to older pipelines.

Standardized Emergency Management System (SEMS)

SEMS is mandated by California Government Code §8607(a), as the means for providing a unified response for all elements of California’s emergency management program, including managing response to multi-agency and multi-jurisdictional emergencies. State response agencies are required to use SEMS, and local government agencies must use SEMS to be eligible for State funding of certain response-related personnel costs resulting from a disaster. SEMS consists of five organizational levels that are activated as needed: field response, local government, operational area, region, and State. This management scheme incorporates the use of the Incident Command System (ICS), master mutual aid agreements, existing discipline-specific mutual aid, the operational area concept, and multi-agency or inter-agency coordination.

Local Emergency Services

Should an incident occur, local fire and police services are already in place and have a proven record in appropriately managing incidents involving natural gas pipelines. When a natural gas distribution line valve was damaged as a result of an automobile accident on Rose Avenue in May 2004, local emergency services and the gas company quickly responded. Traffic was evacuated from roadways within a several-mile area and a nearby high school was “locked down” with students and faculty instructed to shelter in-place as a precautionary measure. This indicates that local services have the knowledge and skills to effectively manage natural gas emergencies. (Note that this incident involved a distribution line, not a transmission line, which is more robustly constructed and generally better protected from impacts than the smaller distribution lines).

Emergency response agencies in Ventura and Los Angeles counties have adopted the SEMS protocols for emergency response. Fire service in the area of the proposed Project pipelines is provided by the Ventura County Fire Department, which provides fire protection services within the unincorporated areas of Ventura County and in the incorporated areas of Port Hueneme and Camarillo. The Oxnard Fire Department provides fire services in the incorporated area of the city of Oxnard. Federal fire departments provide fire services at Point Mugu and Port Hueneme, and the Los

Angeles County Fire Department provides services in the Santa Clarita Valley (see Table 4.2.8-2).

Table 4.2.8-2 Fire and Emergency Medical Services in the Proposed Project Area

Fire Service/Area of Responsibility	Fire Stations in Vicinity of Proposed Project
Ventura County	
Ventura County, Camarillo Plain, South Coast, El Rio, and Port Hueneme	Ventura County Fire Department, Stations 50 to 57: 50 – Camarillo Airport, 189 Las Posas Rd, Camarillo 51 – El Rio, 680 El Rio Rd, Oxnard 52 – Mission Oaks, 5353 Santa Rosa Rd, Camarillo 53 – Port Hueneme, 304 Second St., Port Hueneme 54 – Camarilo, 2160 Pickwick Dr., Camarillo 55 – Las Posas, 403 Valley Vista Dr, Camarillo 56 – Malibu, 11677 E. Pacific Coast Hwy, Malibu 57 – Somis, 3356 Somis Rd, Somis
City of Oxnard	Oxnard Fire Department, Stations 60 to 66: 61 – Station 61, 491 South “K” Street, Oxnard 62 – Station 62, 531 East Pleasant Valley Road, Oxnard 63 – Station 63, 150 Hill Street, Oxnard 64 – Station 64, 230 West Vineyard Avenue, Oxnard 65 – Station 65, 1450 Colonia Road, Oxnard 66 – Station 66, 2601 Peninsula Road, Oxnard
Federal	NWAS Point Mugu (Stations 71 and 72) and NCBC Port Hueneme (Station 73)
Los Angeles County Santa Clarita Valley	Los Angeles County Fire Department, Battalion 6 FS 73 – 24875 N. San Fernando Rd, Newhall FS 75 – 23310 Lake Manor Dr, Chatsworth FS 76 – 27223 Henry Mayo Dr, Valencia FS 77 – 46833 Peace Valley Rd, Gorman FS 107- 18239 W. Soledad Canyon Rd, Canyon Country FS 111 – 26289 Seco Canyon Rd, Valencia FS 123 – 26231 N. Sand Canyon Rd, Canyon Country FS 124 – 25870 Hemingway Ave., Stevenson Ranch **FS 126 – 26320 Citrus Dr., Santa Clarita** FS 149 – 31770 Ridge Route, Castaic

Corporate taxes, franchise fees, and other taxes that would be paid by the Applicant would contribute to the city and county funding for emergency services. Local governments also have the legal authority to conduct cost recovery actions for large-scale incidents requiring unusual expenditures of resources. For disasters, each of the local response agencies also has the option to request State funding, based on having adopted SEMS practices for multi-agency and multi-jurisdictional responses.

The Applicant has proposed the following mitigation measures to reduce the potential of incidents due to operational errors, upsets, or equipment failures or natural phenomena.

AMM PS-6a. **Applicant Would Construct all Pipelines to Meet Class 3 Design Criteria.** The Applicant would construct all pipeline segments to meet the minimum design criteria for a Class 3 location, which will provide an increased level of protection in areas where requirements would be less stringent, based on current population density along the pipeline (i.e., in Class 1 or Class 2 locations).

AMM PS-3c. **Comply with Design, Maintenance, inspection, and testing requirements** also applies here.

<u>Mitigation Measures for Impact PS-6: Natural Gas Release and Fire</u>

MM PS-6b. **Pipeline Integrity Management Program.** The Applicant shall develop and implement a pipeline integrity management program, including confirming all potential HCAs (including identification of potential sites from "licensed" facility information [day care, nursing care, or similar facilities] available at the city and county level) and ensuring that the public education program is fully implemented before beginning pipeline operations.

MM PS-6c. **Include Automatic Shut Down Valves (ASDVs) and Check Valves in HCAs.** The Applicant shall include ASDVs with appropriate blow-down time on the upstream side of the pipeline and check valves on the downstream side in HCAs. This provides additional means for isolating segments of the pipeline should a rupture occur.

MM PS-3d. **Areas Subject to Accelerated Corrosion, Cathodic Protection System** also applies here.

The (unmitigated) annual frequencies of significant events per pipeline mile have been very conservatively estimated for both onshore and offshore pipelines at about 4×10^{-5} per year (four in one hundred thousand) that a pipeline incident would result in a serious public injury and about 1×10^{-5} per year (one in one hundred thousand) that a pipeline incident would result in a public fatality. These frequencies would be expected to be reduced for the proposed Project pipelines—and in some cases significantly decreased—with the implementation of the measures described above. The impacts, however, would still be potentially significant (i.e., could cause serious injury or fatality to members of the public) should an incident occur, e.g., as a result of an intentional attack. Therefore, this impact remains significant after mitigation.

Impact PS-7. Potential for Increased Consequences of Natural Gas Release and Fire in Areas with Less Robust Housing Construction

In the event of an accident, there is a greater likelihood of injury, fatality, and property damage due to fire and explosion in Areas with Less Robust Housing Construction (Class I).

Definitions and guidance provided in 49 CFR 192 for HCAs provide the minimum requirements for determination of HCAs. The equation contained in 49 CF 192 for calculating a PIR is based on the following assumptions (Gas Research Institute 2000):

- People who are outside near the pipe rupture will be able to reach adequate shelter within 200 feet (61 m) of their location, with travel time presumed to be no more than 30 seconds. This assumes that a person takes between 1 and 5 seconds to evaluate the situation and then runs at 5 mph (2.5 m/s) to reach shelter.
- Protection of individuals inside a structure and ignition of nearby structures is based on a "typical" wooden structure, using thermal properties specifically for American whitewood. These wooden structures are presumed to provide adequate protection indefinitely for people who have taken shelter inside them.

It is unlikely that the construction of many older mobile homes (manufactured housing built before 1976 when more stringent construction standards were imposed by the Housing and Urban Development code) or travel trailers being used for temporary or semi-permanent housing would provide this level of protection. Ignition of mobile homes and travel trailers will likely occur at lower radiant heat levels than the typical construction used to develop the PIR equation. Even without ignition, mobile home construction may not be sturdy enough to withstand the potential blast forces when a natural gas release is ignited. In addition, inhabitants of mobile homes often include older or elderly residents and families with small children who would be difficult to evacuate and are very unlikely to be able to run for shelter at 5 mph (2.5 m/s).

The Applicant has incorporated the following into the proposed Project:

AMM PS-6a. **Applicant Would Construct all Pipelines to Meet Class 3 Design Criteria** also applies here.

<u>Mitigation Measures for Impact PS-7: HCA Determination in Areas with Less Robust Housing Construction</u>

MM PS-7a. **Define HCA for any PIR that includes one or more mobile homes. Assist residents to improve emergency planning.** Areas where the PIR includes one or more normally occupied mobile homes or travel trailers used as temporary or semi-permanent housing shall be defined as an HCA. Mitigation measures (e.g., smoke detectors and outreach for notification and escape planning) shall be provided to all residents of that housing.

MM PS-7b. **Define an HCA for areas where the PIR includes part or all of a manufactured-home residential community**. Provide mitigation measures (e.g., smoke detectors and outreach for notification and escape planning) to all residents of that community.

MM PS-7c. **Implement Public Education/Awareness Program.** In accordance with pipeline safety requirements contained in 49 CFR 192 Part O, the Applicant shall develop and implement a public education and awareness program that complies with API's recommended practice (RP) 1162, "Public Awareness Programs for Pipeline Operators," including providing specific information to residents regarding ways to reduce their risks in the event of a fire or other release involving the pipeline and recommended ways to test and maintain household smoke detectors. Mitigation measures shall be implemented to ensure that residents receive early warning of a fire (e.g., install and instruct residents regarding how to maintain smoke detectors), that they are provided information and assistance to plan escape routes, and that they can define how to account for other family members and neighbors to ensure that they have escaped. Additional information specific to residents living in manufactured housing can be obtained from the U.S. Fire Administration fact sheet. "Planning Emergency Escape from Manufactured Homes," which is available at http://fire.nist.gov/factsheets/escape.htm.

The likelihood of potential impacts would be reduced with the implementation of the measures described above, but the impacts would still be potentially significant should an incident occur. Therefore this impact remains significant after mitigation.

Public Safety Impact PS-8. Potential for Increased Injuries or Fatalities in areas with Outdoor Activity.

In the event of an accident, there is an increased potential for injury or fatality near Center Road Pipeline Milepost 4.1 due to Community Activities Outdoors. Observed outdoor uses at the mobile home park on Dufau Road near Milepost (MP) 4.1 are sufficient to warrant designating this area as an HCA (Class I).

The Applicant determined that mobile home parks on Pidduck and Dufau Roads near MP 4.1 of the proposed Center Road pipeline route did not trigger HCA requirements in the EA evaluation, based on the presence of only ten buildings intended for human occupancy within the potential impact circle (PIR of 818 feet [250 m]). A field inspection by E & E staff in August 2004 indicated that the small housing community located on Dufau Road includes community gardens. The arrangement of outdoor furniture and the level of human activity outdoors indicate that there is likely significant community activity outside of the residences.

Based on the average household size in Census Tract 47.02 (U.S. Census Bureau 2000) of about four people, this cluster of ten buildings could reasonably be expected to include the presence of more than 20 people in an outside area on at least 50 days in any 12-month period, which meets the definition of an identified site for the purposes of defining an HCA.

The Applicant has proposed the following mitigation measures to reduce the potential of incidents due to operational errors, upsets, or equipment failures or natural phenomena:

AMM PS-6a. **Applicant Would Construct all Pipelines to Meet Class 3 Design Criteria** also applies here.

<u>Mitigation Measures for Impact PS-8: Define HCA near MP 4.1 on Proposed Center Road Pipeline</u>

MM PS-8a. **Define HCA.** An HCA shall be defined in this area using the mobile home park property boundaries and any garden areas as the edge of an outdoor area that meets HCA criteria.

The likelihood of potential impacts would be reduced with the implementation of the measures described above, but the impacts would still be potentially significant should an incident occur. Therefore this impact remains significant after mitigation.

4.2.9 Alternatives

4.2.9.1 No-Action Alternative

The No-Action alternative means that the Project would not go forward and the FSRU, associated subsea pipelines, onshore odorization facility, and onshore pipelines would not be installed. Since the No-Action Alternative is equivalent to the baseline condition (as described in the environmental setting), there would be no impact on these baseline conditions if the proposed Project were not approved. Energy needs identified in Section 1.3 would likely be addressed through other means, e.g., other energy-related projects or through economic measures such as increased pricing to reduce energy consumption. Any of those scenarios could result in lesser or greater impacts to public safety than the proposed Project, although it would be speculative, at best, to determine what additional measures might be taken if this Project is not implemented. For example, we do not know at this time whether additional pipelines would be constructed or whether other proposed LNG terminals at Long Beach, in Baja, or near Oxnard (Crystal Energy's proposed DWP) would be built.

4.2.9.2 Alternative DWP Location – Santa Barbara Channel/Mandalay Shore Crossing/Gonzales Road Pipeline Alternative

The FSRU mooring point for this alternative would be approximately 8.5 miles (13.7 km) offshore of Rincon Beach and approximately midway between the existing Grace and Habitat production platforms in the Santa Barbara Channel. The alternative mooring location would be located at latitude 34°14.410'N, longitude 119°30.916'W. This alternative would meet safety criteria because it would be more than 3 miles (4.8 km) from shipping lanes and existing facilities. It would be approximately 5.8 NM (6.7 miles or 10.7 km) landward from the coastal shipping lanes and more than 4.2 NM (4.8 miles or 7.8 km) from the nearest offshore production platform.

This proposed alternate location is farther away from coastal shipping lanes, compared to the 2.9-mile (7.9 km) distance to the nearest shipping lane for the proposed Project. The potential frequencies for collisions with the FSRU and various types of vessels analyzed in the Independent Risk Assessment for the proposed Project was specific to the proposed Project mooring location. The increased distance from the nearest shipping lane for the alternative mooring location in the Santa Barbara Channel could be expected to result in reduced potential for large vessel impacts with the FSRU and to lower the potential risk of a release due to a high speed impact with one of these larger vessels.

However, LNG tankers heading for this alternate mooring location would be required to cross vessel separation traffic lanes, and there are greater numbers of fishing and recreational vessels that are likely to be in proximity to this location. This would increase the potential for a collision involving an LNG tanker, and would be expected to increase the number of members of the public that might be affected by impacts from a fire or explosion involving either a tanker or the FSRU. A site-specific risk evaluation would be needed to quantify the potential risks to members of the public if this alternative is selected.

Because this area is subject to more use by recreational and fishing vessels than the proposed mooring location, there would also be an increased potential for collisions of these smaller vessels with the FSRU, LNG carriers, or tug/supply vessels serving the proposed DWP. This could result in an increased number of serious injuries or fatalities to members of the public just from the collision impacts and could result in greater short-term environmental impacts due to releases of oil or fuel from the smaller damaged vessels.

Computer modeling results for credible worst-case LNG releases from the FSRU indicate that significant impacts to the public are limited to areas that are several miles offshore. Although the alternate mooring location in Santa Barbara Channel is closer to shore than the proposed Project, the maximum reach for significant impacts to public safety would still be expected to be a matter of miles offshore.

The alternative pipeline route from the mooring point to Platform Gilda would be in waters approximately 270 feet (82.3 m) deep. The alternate pipeline route would continue in an existing subsea pipeline corridor from Platform Gilda to the Mandalay Generating Station. Like the proposed Project, the alternative pipeline route is proposed to be laid on the sea floor in waters deeper than 43 feet (13 m), at which point (approximately 1.0 NM [1.15 miles or 1.8 km] offshore), it would be buried under an increasing overburden of sediments in an HDD bore from the shore crossing. Although routing the subsea pipelines in an existing, well-known pipeline corridor may reduce the chance for third party damage (e.g., due to dragging an anchor or tangling in trawling gear), the potential impacts to public safety for the subsea pipelines would be similar to those described for the proposed Project.

Although the length of the HDD bore would be slightly longer, and it appears that there would be a longer section of pipe carrying unodorized gas along the shoreline, the potential impacts to public safety from this alternative shore crossing, odorization facility, and connection to an existing SoCalGas natural gas pipeline at the Mandalay Generating Station would be similar to the proposed Project.

From the Mandalay Generating Station, the onshore pipeline would be installed primarily in existing pipeline rights-of-way along Harbor Boulevard, West Gonzales Road, East Gonzales Road, and Rose Road, where it would meet Center Road Pipeline Alternative 1 near MP 8.0.

4.2.9.3 Alternative Onshore Pipeline Routes

Center Road Pipeline Alternative 1

Approximately 1.4 miles (2.3 km) of the proposed route is located in pipeline Class 3 locations (the remainder is routed through Class 1 areas). This alternative route passes through more densely populated areas than the proposed pipeline route, with approximately 6.1 miles (9.82 km) in Class 3 locations and 0.3 mile (0.48 km) in Class 2 locations. There are also greater numbers of HCAs identified along this alternate pipeline route compared with the proposed route. Preliminary evaluation of areas of concern identified three separate locations and an estimated total pipeline length of about 0.9 mile (1.45 km) that would be considered HCAs along the 14.3-mile (23.0 km) length of the proposed pipeline route, compared with twelve separate locations and an estimated 6.15 miles (9.9 km) total pipeline length subject to HCA requirements along the 15.0-mile (24.1 km) alternative route.

Center Road Pipeline Alternative 2

The potential impacts to public safety for this route are the same as for the proposed route from MP 0.0 to about MP 5.8 and from MP 10.8 to MP 15.0, where the routes are identical. From MP 5.8, however, the alternative route follows Pleasant Valley and Wolff rather than backtracking to the southwest on Pleasant Valley before running northward along Del Norte, which travels through a slightly more rural area with less dense housing than the proposed route (resulting in potentially lower impacts to public safety).

Line 225 Pipeline Loop Alternative

The potential impacts to public safety for this route are the same as for the proposed route from MP 0.0 to about MP 4.8 and from approximately MP 6.7 to MP 7.71, where the routes are identical. From about MP 4.8, however, the alternate route continues northwest along Magic Mountain rather than veering northward on McBean, which travels through an area with less dense housing than the proposed route (resulting in potentially lower impacts to public safety).

4.2.9.4 Alternative Shore Crossing/ Pipeline Route

Point Mugu Shore Crossing/Casper Road Pipeline

The potential impacts on public safety for this alternate shore crossing and 1.5-mile (2.4 km) long alternative pipeline route are similar to those associated with MP 0.0 to approximately MP 2.5 of the proposed Center Road Pipeline, which this alternative would replace.

Arnold Road Shore Crossing/Arnold Road Pipeline

The potential impacts to public safety for this alternate shore crossing and 1.5-mile (2.4 km) long alternative pipeline route are similar to those associated with MP 0.0 to approximately MP 1.8 of the proposed Center Road Pipeline, which this alternative would replace.

4.2.10 References

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